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EVALUATION OF STEAM RECOVERY PROCESSES WITH THE ADDITION OF NON-CONDENSIBLE GASES

Final Report

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ABSTRACT

Isothermal, one dimensional linear coreflood tests were conducted on 1.5" x 8" Berea and Brown Sandstone samples. The gas permeability for the Berea sandstone samples ranged from approximately 70 md to 140 md; and for the Brown sandstone it ranged from approximately 600 md to 3800 md. Heavy oil samples of Athabasca bitumen and Lloydminster crude were used (as the displaced phase) to saturate the core samples.

The objective of the program was to identify and evaluate the role of the following mechanisms in thermal recovery processes:

1. Thermal expansion
2. Connate water flashing
3. Oil natural liveness
4. Dissolution/evolution of gaseous additives
5. Mechanical stripping
6. Chemical stripping

The study was conducted in 4 phases. Phase 1 was a procedure validation phase in which 4 test runs were performed for the purpose of confirming the procedures. Phase 2 included 33 coreflood runs using "dead" Athabasca bitumen as the displaced phase; Phase 3 included 12 coreflood runs using artificially saturated Athabasca bitumen as the displaced phase; and Phase 4 included 32 coreflood runs using recombined "live" Lloydminster crude as the displaced phase.

The runs were performed in two experimental recovery process types. Experimental Type 1 included determining oil recoveries after each of the 4 consecutive stages of heat-up (from 80 C to 250 C), hot-waterflooding (sometimes with additives), pressure drawdown (flashing), and steamflooding (sometimes with additives). Experimental Type 2 included determining oil recoveries after each of the 3 consecutive stages of heat-up (from 80 C to 250 C), pressure drawdown, and steamflooding (sometimes with additives). The additives (sometimes) injected during waterflooding or steamflooding to enhance recovery were nitrogen, carbon-dioxide, and methane.

The recovery results are expressed in terms of the percentage of the original oil in place, and are compared with the recoveries of the baseline runs (the baseline runs were the runs without additives).

In this report, the effects of each of the non-condensible additive, and the role each recovery mechanism plays in improving oil recovery, are described and evaluated.

RESUME

Des tests d'injection linéaires à une dimension et isothermiques ont été effectués sur des échantillons de grès Berea et Brown de 1,5" x 8". La perméabilité du gaz pour les échantillons de grès Berea allait d'approximativement 70 md à 140 md, et pour le grès Brown, d'approximativement 600 md à 3800 md. Pour saturer les carottes, des échantillons de pétrole lourd du bitume d'Athabasca et de pétrole brut Lloydminster (comme phase déplacée) ont été utilisés.

L'objectif de ce programme était d'identifier et d'évaluer le rôle des mécanismes suivants, présents dans les procédés de récupération thermique:

1. Expansion thermique
2. Détente d'eau connée
3. Vivacité naturelle du pétrole
4. Dissolution/évolution des additifs gazeux
5. Désessençage mécanique
6. Désessençage chimique

L'étude a suivi 4 phases. La phase no. 1 était une phase de validation de procédure dans laquelle 4 marches témoins ont été realisées dans le but de confirmer les procédures. La phase no. 2 incluait 33 marches d'injection, utilisant du bitume "mort" d'Athabasca comme phase déplacée. La phase no. 3 comprenait 12 marches d'injection, utilisant du bitume artificiellement saturé d'Athabasca comme phase déplacée. Enfin, la phase no 4. comprenait 32 marches d'injection, utilisant du pétrole brut Lloydminster vivant recombiné comme phase de deplacement.

Les marches témoins se sont déroulées selon 2 types de procédés expérimentaux de récupération. Dans le type expérimental no 1 il s'agissait de déterminer les récupérations pétrolières après chacune des 4 étapes consécutives de chauffage (de 80 C à 250 C), d'injection d'eau chaude (parfois avec additifs), d'abaissement de pression (détente), et d'injection de vapeur d'eau (parfois avec additifs). Dans le type experimental no. 2 il s'agissait de déterminer les récupérations pétrolières après chacune des 3 étapes consécutives de chauffage (de 80 C à 250 C), d'abaissement de pression et d'injection de vapeur d'eau (parfois avec additifs). Les additifs (parfois) injectés au cours de l'injection d'eau et de l'injection de vapeur d'eau le but d'augmenter la récupération étaient l'azote, le gaz carbonique et le méthane.

Les résultats de la récupération sont exprimés en termes du pourcentage du pétrole original en place, et sont comparés avec les récupérations des marche de base (les marches de base étaient celles sans additifs).

Ce rapport décrit et évalue les effets de chaque additif non-condensable et le rôle que joue chaque mécanisme de récupération dans l'amélioration de la récupération pétrolière.

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1. INTRODUCTION

The Athabasca and Lloydminster deposits in Alberta and Saskatchewan are two of the major petroleum reserves of the world. However, because of the high viscosity of the bitumen, these crudes have very little or no mobility at reservoir conditions. This makes the recovery of oil uneconomical with the present recovery processes in use. However, it is anticipated that with increased field activity and laboratory research, large volumes of oil can be produced economically from these reservoirs.

To lower oil viscosity and therefore increase oil mobility, considerable laboratory research has been done in the area of thermal recovery. Recently, particular attention has been given to the study of additives-with-steam processes. Many studies have been undertaken to address the question of whether non-condensible gaseous additives improve oil recovery in steam based processes. No conclusive answer has been found to date.

The present report describes a study of the mechanisms involved in non-condensible gaseous additives in steam recovery processes. By understanding the mechanisms of the recovery process, the question of additives improving oil recovery will be answered in a more scientifically conclusive fashion.

1.1 Background

Thermal recovery processes are of three types: cyclical stimulation (huff-and-puff), steam-drive and steam-drive with pressure cycling. All of these processes have been suggested as applications for steam with additives.

Previous experimental investigations of oil recovery by means of steam-with-additives processes have been of two types: large three dimensional elemental models and linear core floods. Large elemental modelling studies have been performed at the Alberta Research Council (ARC)[1]. Although some of the results have been published, the greatest part of this data is confidential. The linear core flood tests were performed at the University of Alberta[2]. In addition to recovery tests, considerable work has been performed on physical property (viscosity, density) modification due to the dissolution of certain gases in oil[3,4,5]. Based on results published to date, the following conclusions can be drawn:

1. The injection of non-condensible gas improves the recovery rate; whether ultimate recovery is affected, is not known with certainty.

2. Carbon-dioxide (CO_2) appears to be the most beneficial additive, although the ARC results suggest that a steam-CO_2-naphtha process is the best.

3. The primary mechanism responsible for improved performance is the additional drive supplied by the non-condensible gas. This is particularly important during cycling processes, which cause dissolved gases to evolve.

4. Dissolution and diffusion of the additive causes a swelling of the oil and a reduction of its viscosity (particularly for CO_2).

5. During flowthrough experiments, the presence of a non-condensible gas maintains pressure gradients. In a steam-drive, the condensation of the steam causes a reduction in the volumetric flowrate, hence the pressure gradiet within the reservoir. The reduced pressure gradient imposes less of a displacement force across the oil in place, thereby slowing or even preventing recovery. The addition of a non-condensible gas phase helps maintain the pressure gradient, hence increasing oil recovery rates.

   Laboratory experiments may be influenced by three phenomena which are completely unrelated to the presence of a non-condensible gas: the inherent liveness of the oil, flashing of the connate water and the thermal expansion of the reservoir fluids. Until the roles which these phenomena play are clearly understood, the interpretation of existing and future experimental results must be held suspect.

1.2 Program Objective

An experimental program was conducted to study recovery mechanisms for the three thermal recovery methods previously mentioned: cyclical stimulation, steam-drive, and steam-drive with pressure cycling. Some of the processes that are involved in these recovery methods are: heat-up, hot-waterflooding, pressure drawdown, and steamflooding. In this program these processes were combined into four (4) experimental phases, of which Phase 1 was conducted to validate experimental procedures (see previous report submitted to the Department of Supply and Services of Canada on January 30, 1987 for the results of Phase 1.)

Non-condensible gaseous additives (nitrogen, carbon dioxide and methane gases) were added with water and steam during waterflooding and steamflooding processes to evaluated their effectiveness in improving oil recovery. The oil recoveries obtained from the experimental tests were studied in detail to evaluate the role of the following mechanisms:

1. Thermal expansion
2. Connate water flashing
3. Natural liveness of oil
4. Dissolution/evolution of gaseous additives
5. Mechanical stripping (viscous drag)
6. Solution stripping (swelling and viscosity reduction in the oil)

In each of the three phases (Phases 2,3 & 4), a different type of oil was used in order to facilitate a more conclusive evaluation of the role of the above mechanism. The oils used were as follows:

Phase 2: "Dead" Athabasca bitumen
Phase 3: Athabasca bitumen saturated with nitrogen,
Athabasca bitumen saturated with methane,
Athabasca bitumen saturated with carbon dioxide
Phase 4: "Live" Lloydminster crude

1.3 Scope of work

One dimensional linear corefloods were conducted at isothermal conditions using two basic experimental types (Experimental Type 1 and 2). The first 2 steps in both experimental types were identical. These steps were as follows:

1. The pore pressure was raised to above the saturation pressure of steam (7 - 8 Mpa).
2. The system was heated to the temperature of 250 C.

Experimental Type 1, followed as follows:

1. Water, sometimes combined with a gaseous additive, was passed through the core at a fixed flowrate for a fixed period of time.
2. The pressure was lowered to below the flash point of the water (2 Mpa).
3. Steam, sometimes combined with a gaseous additive, was passed through the core at a fixed flowrate for a fixed period of

time. Total mass injection was the same as in Step 1.

Experimental Type 2, followed as follows:

1. The pressure was lowered to below the flash point of the water (2 Mpa).
2. Steam, sometimes combined with a gaseous additive, was passed through the core at a fixed flowrate for a fixed period of time. Total mass injection was the same as in step 1 of Experimental Type 1.

The corefloods were conducted on two types of consolidated sandstones, Berea and Brown sandstones. The permeability of the Berea samples were classified as low (approximately 100 md), and the Brown sandstone samples were classified as high permeability (approximately 1000 md). For the Berea samples, good consistency of permeability was achieved; for the Brown sandstone samples, however, the permeabilities varied widely due to vertical bedding planes in the core.

In addition to the above experimental types and sample types for each run, a repeat run using a new sample was conducted for the purpose of reproducibility.

The experimental program was based on a statistical design, so as to optimize the utility of the resulting data. In all, a total of seventy eight (78) experiments were designed to be conducted. However, due to experimental problems, 3 additional runs were conducted for a total of eighty one (81) runs.

Phase 2: Runs with "Dead" Athabasca bitumen

Four flooding fluids were tested in this phase. These were: water/steam, water/steam with methane, water/steam with carbon dioxide, and water/steam with nitrogen. Both Experimental Type 1 and 2 were conducted. The experimental program, therefore, consisted of 4x2x2x2 or 32 runs.

Phase 3: Runs with artificially saturated Athabasca bitumen

Only Experimental Type 2 was conducted in this phase. No additives were injected during recovery. The experimental program, therefore, consisted of 3x2x2 or 12 runs.

Phase 4: Runs with "Live" Lloydminster crude

Four different flooding fluids were tested: water/steam, water/steam with methane, water/steam with carbon dioxide, and water/steam with nitrogen. Both Experimental Type 1 and 2 were conducted. The experimental program therefore consisted of 4x2x2x2 or 32 runs.

The recoveries were defined in terms of the percentage of the original oil-in-place at the end of each of the following stages.

Experimental Type 1:

1. Recovery after heat-up.
2. Recovery after waterflooding.
3. Recovery after pressure drawdown.
4. Recovery after steamflooding.

Experimental Type 2:

1. Recovery after heat-up.
2. Recovery after pressure drawdown.
3. Recovery after steamflooding.

2. CORE SAMPLE DESCRIPTION

Two types of core samples were used in all phases of this study, the Berea sandstone (refered to as low permeability samples), and the Brown sandstone (refered to as medium and high permeability samples). A photograph of a typical sample of each type is shown in Figure 2.1. The petrophysical properties of each sample is listed in Tables 2.1, 2.2, and 2.3.

2.1 Geological Description of the Berea Sandstone

Thirty eight (38) samples of this core were used in this study. In general, the samples were similar in porosity and gas permeability. The gas permeabilities ranged from 74 md to 145 md, and the porosities ranged from 17.2% to 20.3%. The arithmetic mean for the gas permeabilities was 104.48 md, and for the porosity was 18.18%. The standard deviation for permeability was 17.98 md, and for porosity was 0.75%.

The Berea sandstone is a moderately well sorted, predominantly fine grained sublitharenite with very good visible porosity and permeability. Modified primary intergranular porosity and secondary macroporosity after removal of unstable grains was most common. Remnant ferroan calcite cement locally reduces porosity and permeability and many of the enlarged pore throats resulted from removal of previously precipitated ferroan calcite cement. Quartz overgrowths had formed on monocrystal throats. Kaolinite was present in minor amounts; however, grain-rimming and pore-blocking clays were not common. Smectite clays were not present as a component of rock fragments. Therefore a swelling problem was not anticipated. Authigenic or recrystallized detrital kaolinite was irregularly distributed and migration of loosely attached kaolinite may have had a slight reducing effect on permeability. Minor authigenic siderite locally reduces porosity.

2.2 Geological Description of the Brown sandstone

The Brown Sandstone is not as homogeneous as the Berea Sandstone. For most samples, vertical bedding bands (planes) were present which often extended from one end of the sample to the other. The width of the bands varied from sample to sample, which influenced the permeability and /or the porosity of the sample. The petrophysical properties, especially the gas permeabilities varied widely. There were 41 Brown sandstone samples used in this study, for which the gas permeabilities varied from 616 md to 3760 md, and the porosities ranged from 20.2 % to 23.8 %. The arithmetic mean for permeability was 1,714.79 md and for porosity was 21.65%.

The standard deviation for permeability was 1,123.59 md and for porosity was 1.05%.

The Brown sandstone is a moderately sorted, fine to lower coarse grained sublitharenite characterized by excellent visible porosity and permeability. Monocrystalline quartz was the principal framework grain with lesser chert, polycrystalline quartz, sodium feldspars and rock fragments. Detrital muscovite and biotite were present in minor amounts. On the basis of both thin section and SEM examination, recognized authigenic minerals included: discontinuous quartz overgrowths on monocrystalline quartz grains, possible minor authigenic kaolinite, and an oxide material which replaces portions of argillaceous clasts and detrital clays. Recrystallized detrital kaolinite and illite clays were the most common clay types observed. Sodium peaks were not detected on any of the clays analazyed and the presence of smectite was not anticipated. The recrystallized kaolinite booklet size was very small when compared with pore throat size and a significant permeability reduction resulting from migration of minor kaolinite was not anticipated. The presence of pore-lining relatively amorphous kaolinite and kaolinite/illite had reduced the size of many pore throats; however, open pore throats in the range of 120 microns or larger were common. Authigenic kaolinite booklet size was approximately in the range of 6 to 10 microns.

2.3 Geological differences between the Berea and the Brown Sandstone

In general, the Berea sandstone has smaller pore size and pore throat size than the Brown sandstone. Smaller pore and pore throat size is associated with the overall finer grain size in Berea sandstone. Berea pores are much cleaner than those of the Brown sandstone; however, very good measured permeability in the Brown sandstone indicate that pore-lining pore-throat-blocking illitic clays has a limited permeability reducing effect.

2.4 Sample Selection Criterion

In general, samples were classified as the "low", "medium" and "high" permeability. The low permeability samples were refered to the Berea sandstones, and the medium and the high permeability samples were refered to the Brown sandstones. The medium permeability range was only used for the purpose of averaging the irreducible water saturations and is only refered to in the data analysis section of this report.

For each phase of this study, pairs of samples from the low and the high permeability samples were selected. The pairs were selected based on the values of their porosity and permeability. Since repeat runs were to be performed, attempts were made to select two matching samples that had similar porosities and permeabilities.

For the low permeability samples, the samples in each pair were similar. For the high permeability samples, with the exception of two sets, the remaining sets were similar. The two pairs that were not similar, were Runs #5 and #6 as a pair in Phase 2 with values of 3,369.17 md and 1,854.43 md; and Runs #25 and #26 in Phase 2 with values of 1,227.81 md, and 635.92 md.

3. EXPERIMENTAL PROCEDURE

A brief summary of the experimental procedure was discussed in Section 1.3. The detail procedure is discussed here.

3.1 Apparatus

A schematic of the experimental equipment appears in Figure 3.1. The equipment consists of several 2000 ml stainless steel high-pressure transfer cylinders, connected to a high pressure stainless steel visual cell of approximately 212 ml capacity. The equipment also consists of a coreholder designed for 8 inch long cores, 3 Rosemount differential pressure transducers, rated to 35 MPa, which measure differential pressure across the sample in three ranges of 0-14 KPa, 0-140 KPa, and 0-1400 KPa; a condenser placed before the visual cell to ensure condensation before collecting in visual cell; a back pressure regulator rated to 70 MPa with accuracy of +/- 1%; and a high pressure in-line massflow controller/meter to controll the flow of methane, nitrogen and carbon dioxide in the gaseous phase.

A schematic and a photograph of the coreholder assembly is shown in Figures 3.2, and 3.3, respectively. A two component teflon and lead sleeve mechanism was used for each sample to maintain overburden pressure. The samples were inserted into a teflon sleeve prior to inserting into a lead sleeve. The reason for using a teflon sleeve was that at high temperatures (i.e. 250 C), lead becomes very soft and penetrates into the outter pores of the sample, causing permeability reduction. The teflon sleeved sample is then inserted into a 1.50 x 1.75 inches lead sleeve. The ends of the lead sleeve is then mechanically sealed onto the end mandrels to prevent pressure loss from the overburden. The assembly is then placed into the coreholder and the pressure lines (injection and production) are connected.

3.2 Sample Preparation and dimensions

The Berea and the Brown sandstone samples used in this study, were cored using a 1.5 inch bit. No further cutting of the diameter was required since the testing was performed on 1.5 inches diameter samples. The core pieces received from the field were in 24 inch lengths. Each length was cut to 8 inches lengths. The original samples were cleaned using the following solvents: toluene, methanol, and acetone. After cleaning, each sample was dried at 80 C for a period of 24 hours. The nominal dimensions of each sample was 3.81 cm in diameter and 20.32 cm in length.

3.3 Test Procedures

Experimental Type 1 consisted of saturating each sample to 100% of pore volume, followed by oilflooding to irreducible water saturation (performed at 80 C), followed by heating to 250 C, followed by hot waterflooding at 250 C (sometimes with additives), followed by pressure drawdown at 250 C, and finally steamflooding (sometimes with additives) at 250 C.

Experimental Type 2 was similar to Experimental Type 1, with the exception of exclusion of hot waterflooding before pressure drawdown. The details of each process is as follows:

3.3.1 Saturation with Water to 100%

Once each sample was mounted in the coreholder and placed in the oven, the sample was evacuated. Under vacuum, water was imbibed into the sample to achieve 100% saturation. The system was then pressurized with water to the appropriate pore and overburden pressures. Two pore volumes of water were injected to establish fluid continuity and ensure 100% saturation. The temperature was then raised to 80 C. The flow of brine was stopped once the differential pressure across the sample stabilized.

3.3.2 Oilflood to Irreducible Water Saturation

The oilflood was performed at a flowrate of 20 ml/hr for a total of 2 pore volumes.

To measure the water displaced by the oilflood, two experimental procedures were used. The first procedure was used in the first 24 runs of Phase 2 (in all runs of Phase 3, and in the first 13 runs of Phase 4), and the second procedure was used in the remaining runs. The main difference between the two procedures was the location where the water displaced from sample was colleted. In the first technique, the water was collected in the sightglass and the readings were taken from sightglass which was located outside of the oven. In the second procedure, the water was collected in a 500 ml pressurized cylinder inside the oven. For the second procedure, after the oilflood was completed, the water in the sample was measured by an extraction method (Dean Stark). The second procedure was determined to be a more accurate technique.

Once the differential pressure across the sample was stabilized, the fluids in the line downstream of the sample were flushed with water through the by-pass port to remove any oil that may have remained in the downstream dead volume.

3.3.3 Heat-up

The sample was isolated from the injection end, and the oven temperature was raised to 250 C. The overburden pressure and the pore pressure were maintained constant during the heat-up stage by pressure relief valves which relieved the expanded fluids caused by thermal expansion.

The oil produced as a result of the thermal expansion was collected in the sightglass and measured. Once the heat-up stage was completed, the downstream line of sample was flushed with water to remove any oil that may have remained in the line.

3.3.4 Hot Waterflooding/with or without gaseous additives

The mass injection rate of water (and simetimes gaseous additives) was controlled at 0.02 kg/hr for all runs. In the case of hot waterflooding with gaseous additives, the gas was injected at a rate of 0.04 kg/kg of water, but the total flow rate (water plus gaseous additive) flowrate was kept constant at 0.02 kg/hr. The flowrate of water was metered using a positive displacement pump and the flowrate of gas was metered using a gas flowmeter. Both were monitored at room temperature.

In the case of hot waterflooding with no-additives, water was injected through the injection ports into the sample. In the case of hot waterflooding with additives, water and gas were simultaneously but separately injected at the pre-determined flowrates.

Oil was collected in the sightglass and readings were taken as a function of time. The corresponding differential pressures and the total outflow were also measured as a function of time. In total, two mass equivalent pore volumes of water were injected.

3.3.5 Pressure Drawdown Process

In Experimental Type 1, pressure drawdown followed hot waterflooding, whereas in Experimental Type 2, it followed the heat-up stage.

In this process, the upstream end of the sample was isolated, and the pore pressure was lowered from the original pore pressure (see Section 3.5 below) to 2 Mpa (steam pressure). The temperature was maintained at 250 C during this stage. At steam conditions, superheated steam was generated.

As the pressure was slowly lowered to steam pressure, the oil produced from this stage was collected in the sightglass. Once the pressure was lowered and oil production stopped, sufficient volume of steam was pumped through the by-pass port of the coreholder to displace any oil in the downstream of the sample into the sightglass.

3.3.6 Steamflooding/With or Without Additives

The total mass injection rate of steam was controlled at 0.02 kg/hr. In the case of steamflooding with gaseous additives, the gas was injected at a rate of 0.04 kg/kg of steam, keeping the total steam and gas injetion rate at 0.02 kg/hr.

To generate steam, water was injected at a constant flowrate through a coiled tubing into the oven. In the oven, at the temperature of 250 C and pressure of 2 Mpa, the water was converted to superheat steam.

For the steamflooding without additives, similar to the hot waterflooding process, steam was injected through the 'water' port through the sample. For the case of steamflooding with-additives, gas was injected simultaneously but separately with steam into the sample.

Oil from this phase was produced into the sightglass. The sight glass readings together with the differential pressures and the total outflow were recorded as functions of time.

3.4 Fluids Information

The fluids used in each phase were as follow:

Phase 2:

Oil: "Dead" Athabasca bitumen was sampled from Alberta's McMurray mined oil sands (Suncor's coker feed). The bitumen had an API gravity of about 10.1 degrees and a viscosity of approximatley 166,000 cp at 15 C.

Water: A 3% solution of NaCl for the first 24 runs and distilled water for the last 8 runs (methane runs). Distilled water was used for the 8 methane runs, since chlorine in the brine was considered unsafe at 250 C in the presence of methane gas.

Gaseous additive: The additives used in the water and steam flood were nitrogen, carbon-dioxide and methane.

Phase 3:

Oil: Athabasca bitumen, artificially saturated with the non-condensible additives: nitrogen, carbon-dioxide and methane. The Athabasca bitumen was artificially saturated at 80 C to the following bubble point pressures:

Athabasca artificially saturated with nitrogen : 5.5 Mpa
Athabasca artificially saturated with carbon-dioxide: 7.0 Mpa
Athabasca artificially saturated with methane : 5.8 Mpa

The pressure-volume plot and data for each of the "live" oil recombination tests is contained in the Appendix.

Water: A 3% solution of NaCl brine.

Gaseous additive: None

Phase 4:

Oil: "Live" Lloydminster crude. The Lloydminster crude was sampled from the Saskatchewan side of the Lloydminster field. The sample was obtained from Husky Oil's primary production. The "dead' crude had an API gravity of 13.9 degrees, and a viscosity of 11000 cp at 15 C. The oil was mixed in the laboratory with a synthetic solution gas to bubble point pressure. The make-up of the solution gas was as follows:

methane : 95%
ethane : 3%
propane : 1%
n-butane: 1%

Because of the number of runs (32) involved in this phase, 6 batches of the "live" oil were prepared. The bubble points of batches were as follows:

Batch #1: 7.2 Mpa (used in waterflood/no-additive runs)
Batch #2: 6.8 Mpa (used in waterflood/no-additive runs)
Batch #3: 7.2 Mpa (used in waterflood/nitrogen runs)
Batch #4: 7.1 Mpa (used in waterflood/nitrogen runs)
Batch #5*: 5.1 Mpa (used in waterflood/carbon-dioxide runs)
Batch #6: 7.0 Mpa (used in waterflood/methane runs)

(* The bubble point pressure for batch #5 was set at 5.1 Mpa in order to be below the critical pressure of carbon-dioxide during hot waterflooding.)

The Pressure-Volume plots and data for each of the "live" oil recombination tests are contained in appendix.

Water: Distilled water.

Gaseous additives: Nitrogen, carbon-dioxide, and methane.

3.5 Pressure and Temperature Conditions

The following operating conditions of pressure and temperature were used in the tests.

Temperature during oilflooding = 80 C

Temperature at the end of heat-up, and during waterflooding, pressure drawdown, and steamflooding for all the runs = 250 C

Overburden pressure for all the runs = 18 Mpa

Pore pressures in each phase were as follows:

Phase 2:
all runs: = 7 Mpa

Phase 3:
runs with nitrogen saturated Athabasca = 7 Mpa
runs with carbon-dioxide saturated Athabsaca= 8 Mpa
runs with methane saturated Athabasca = 7 Mpa

Phase 4:
runs with no additives = 7.5-8.0 Mpa
runs using nitrogen additive = 7.5-8.0 Mpa
runs using carbon-dioxide additive = 5.5-9.5 Mpa
runs using methane additive = 7.5-8.0 Mpa

3.6 Thermal Expansion Test

Thermal expansion tests were performed on the following oils:

1. "Dead" Athabasca bitumen for Phase 2.
2. Nitrogen saturated Athabasca for Phase 3.
3. Carbon dioxide saturated Athabasca for Phase 3.
4. Methane saturated Athabasca for Phase 3.
5. "Live" Lloydminster oil for Phase 4..

There were two reasons for conducting the thermal expansion test. One, to determine the thermal expansion (swelling factor) of each oil at various temperatures, and two, to determine the density of live oil (artificially saturated) above ambient temperature.

Figure 3.4 shows the schematic of the apparatus used for this test. The procedure was as follows. A predetermined volume of oil (dead, live or artificially saturated) was pumped into a 500 ml prepressurized cylinder (pressurized with water). The exact volume of the oil pumped into the cylinder was determined by measuring the displaced volume of water.

Next, the system temperature was raised in 20 degree steps from 80 C, and allowed to stabilize at each temperature. During heating, both oil and water were expanded, and a volume of water equal to the total expanded volume of both oil and water was displaced through a back pressure regulator. The corresponding weights measured at each temperature for each oil are contained in the Appendix. It should be noted that the baseline temperature from which thermal expansions were measured was 80 C. The reason being that the oilflooding to irreducible water saturation tests were performed at 80 C.

With the known volume of the oil and water in the system at 80 C, and the known thermal expansion of water, and the produced mass of water at each temperature, the thermal expansions of the oil at each temperature was calculated. The thermal expansions are discussed in Sections 4.1.3, 4.2.3, and 4.3.3.

3.7 Emulsion Test

An emulsion test was performed to measure the water/oil ratio in the following processes: heat-up, hot waterflooding, pressure drawdown, steamflooding. Run #27 in Phase 2 (see Table 4.1) using "dead" Athabasca bitumen as the displaced phase, and methane gas as the representative additive, was performed for this purpose.

In this run, at the end of the heat up stage, the oil which was collected in the sightglass was drained into a beaker and measured. The sightglass was kept isolatd from the rest of the system during the draining so that pressure drop on the rest of the system would not occur. The oil and water mixture was spun in an ultracentrifuge at 16,000 rpm and a temperature of 90 C to separate water and oil. The volume of water was then measured.

This procedure was repeated for each stage of the flooding (i.e., hot waterflooding, pressure drawdown and steamflooding). The percentage of water in each stage were as follows:

Heat-up : nil
Hot waterflooding : 1 %
Pressure drawdown : 10 %
Steamflooding : 2.5%

4. DATA ANALYSIS AND REDUCTION

4.1 PHASE 2: "DEAD" OIL TESTS USING ATHABASCA CRUDE

The procedure for analyzing each set of data is discussed in detail. It is shown how the original laboratory data is reduced to the final form in Table 4.12. In total, 33 runs were performed in Phase 2 (16 of which used low permeability samples, and 17 high permeability samples). In all runs, volumetric phase productions were measured by using a sightglass, while total mass flow was measured by using a balance. All calculated values reported here have been converted to mass units. The discussions include the calculation of the following five values:

1. Irreducible water saturation
2. Original mass of the oil in place at S_{wi}
3. Thermal expansion recovery as % OOIP
4. Hot waterflood recovery as % OOIP
5. Flash recovery as % OOIP
6. Steamflood recovery as % OOIP

4.1.1 Irreducible water saturation

As discussed in the experimental procedure, two procedures were used to measure the water produced during oilflood to irreducible water saturation. In the first 24 runs (8 runs with no-additives, 8 runs with nitrogen, and 8 runs with carbon dioxide), the displaced water was measured in the sightglass, and in the last 9 runs (runs with methane), the displaced water was measured in a collecting cylinder located immediately after the sample. Also, in the first 24 runs, a solution of 3% NaCl was used to saturate the samples to 100%, while in the last 9 runs (runs with methane as the additive) distilled water was used instead.

As previously discussed, the oilflood was conducted at 80 C. The temperature at which the volume of the water produced by oilflood was collected, varied from sample to sample. The temperature for each run was recorded for use in volumetric mass conversion calculations.

The density of water at 80 C was used to convert the volume of water in each sample at 100% saturation to mass units. To calculate the equivalent mass of water which was produced by the oilflood, the volume of produced water was multiplied by the density of water at the collected temperature.

The irreducible water saturation (S_{wi}) was then calculated using the following equation:

$$S_{wi} = \frac{\text{Original mass of water in place prior to oilflood} - \text{mass of water produced during oilflood}}{\text{original mass of water in place prior to oilflood}} \times 100$$

The original data which include the density of water at sight glass temperature, the corresponding calculated values in terms of mass, and the irreducible water saturations for each sample are presented in the Appendix.

Experimental problems were experienced during oilflooding to irreducible water saturation for a few runs. These runs were Runs #2, #3, #9, #10, #13, #16, and #20 with irreducible water saturations of 42.64%, 10.62%, 34.25%, 37.39%, 39.89%, 30.01%, and 32.38%, respectively. The problems in all cases were associated with sightglass readings and measurements. In six of the seven runs above, where the S_{wi} values are above 30%, a clear interface between water and oil could not be maintained. It is very likely that in these cases, water was trapped in oil, resulting in an irregular interface, and subsequently resulting in a low volume of produced water reading. In the case of the low irreducible water saturation (10.62%), the experimental problem was a density inversion that occurred in the sightglass, resulting in a high volume of produced water reading, and therefore a low S_{wi}.

Since the above 7 runs contained errors in the S_{wi} values, average values were used in lieu of these values. This was done in order to make use of the results of other stages in these runs. The justification for using average values was that the experimental techniques and the procedures and the type of oil used in the all oilfloods were the same. The only variable that would affect the irreducible water saturations was the permeability.

For this reason, the runs were divided in three permeability groups of low, medium and high. These groups contained samples which had permeabilities similar to the 7 runs above. As a results, some runs that did not fall in either of the above groups, were not used in the averaging. For example, the low permeability group consisted of 13 samples with permeabilities in the 70 md to 150 md range. The medium permeability group consisted of 5 samples with permeabilities in the 600 md to 1250 md range, and the high permeability group consisted of 7 samples with permeabilities in the 2500 md to 3800 md range. The geometric mean irreducible water saturations for each group was determined. The results are shown in Table 4.1. Table 4.2 shows the values of S_{wi} for all runs, after the values of the 7 runs were replaced with the average values.

4.1.2 Mass of the Original Oil-in-Place

The mass of the original oil in place was calculated by the following equation:

$$M_{ooip} = (M_w - (M_w \times S_{wi}))(D_o/D_w)$$

where

M_{ooip} = mass of the original oil in place
M_w = total mass of water in place before oilflood
D_o = density of oil at 80 C
D_w = density of water at 80 C

The density of the Athabasca bitumen at 80 C was 0.975 g/cc. The values for the mass of the original oil in place are shown in Table 4.7.

4.1.3 Heat-Up Recovery as %OOIP

Due to the presence of oil and water in the upstream and downstream dead volumes, it was necessary to conduct experiments to determine the thermal expansion of both the water and the Athabasca bitumen. Since the volumes of each fluid in the dead volume were known before heat-up, the contribution of each fluid to the total recovery was calculated using the thermal expansion of each fluid. The contribution of water was to displace a volume of oil equivalent to its thermal expansion, and the contribution of oil was a volume equal to its thermal expansion of the volume left after water thermal expansion correction was applied. Table 4.3 shows the thermal expansion data for the brine.

Figure 4.1 shows the thermal expansions for the 3% brine at each temperature. The data shows that heating the 3% brine from 80 C to 250 C, causes a volumetric expansion of 17.8%. This value was applied for the brine in the dead volume of the system to account for the displacement of the oil caused by thermal expansion of water.

Table 4.4 shows the data which was obtained by heating the "dead" Athabasca bitumen from 80 C to 250 C. Figure 4.2 shows the thermal expansion of the "dead" Athabasca bitumen with temperature. The above data shows that heating the "dead" Athabasca bitumen from 80 C to approximately 250 C, will result in a thermal expansion of 12.67%.

The dead volumes as calculated above were subtracted from the total sightglass readings to give the net heat-up recovery volume. The dead volume calculations for the methane runs were slightly different, since as described previously (Section 3.5.3), the downstream plumbing for the methane runs was different. Also, distilled water used in these runs and not the 3% brine. This required that the thermal expansion of the distilled water from 80 C to 250 C, be used. The thermal expansions for distilled water were calculated from steam tables.

The data shows that the thermal expansion for distilled water from 80 C to 250 C is 21.27%, which is higher than for the 3% brine. Figure 4.3 shows the thermal expansions of distilled water at each temperature.

The dead volumes of oil and water for the modified plumbing system were determined and the thermal expansions for both fluids were applied as discussed previously.

The correction for water/oil emulsion in this stage of the experiment was negligable as determined by the emulsion test described in Section 3.7. No emulsion correction was applied here.

To calculate the mass of the oil recovered, the density of the oil at each sightglass temperature was determined. The sightglass temperature for each run in this stage was recorded. Figure 4.4 shows the density of the "dead" Athabasca bitumen oil density as a function of temperature. For each run, the volume of the recovered oil determined previously was multiplied by the density of the oil at sightglass temperature to yield the mass of oil. The mass was then divided by the original mass of the oil in place (determined in Section 4.1.2), to determine percent oil recovered by the heat-up stage as %OOIP. Table 4.6 shows the mass and the recoveries for the heat up stage.

4.1.4 Hot Waterflood Recovery as %OOIP

The volume of oil recovered in the hot waterflood stage was corrected for water/oil emulsion and then converted to units of mass. The emulsion test described in Section 3.7 showed that there was about a 1% water in the produced oil during hot waterflood with methane. This value, although small, was applied uniformly to all runs, regardless of the type of the additive. The sightglass temperature was continuously monitored and recorded during the hot waterflood. In each run, the final sightglass temperature was used for oil density determination. The corrected volume of oil was then multiplied by the density at sightglass temperature (Figure 4.4) to determine the mass of oil recovered from the hot waterflood. The mass of the oil was then divided by the mass of the original oil in place to obtain the percent waterflood recovery as %OOIP. The results are presented in Table 4.7.

4.1.5 Pressure Drawdown Recovery as %OOIP

The volumes of pressure drawdown recoveries as measured in the sightglass were first corrected for water/oil emulsion and then converted to mass units. The volumes of oil recovered in both Type 1 and Type 2 experiments were corrected by a factor of 1.1 as determined in the emulsion test (Section 3.7). As discussed previously, the emulsion test was a Type 1 test and included a waterflood prior to pressure drawdown. The same emulsion correction factor, however, was applied to both types of experiments. It is possible that the water/oil emulsion ratio may have been different for a pressure drawdown process that is not preceeded by a hot waterflood.

Once the emulsion correction factor was applied, the density of the oil at sightglass temperature (from Figure 4.4) was multiplied by the corrected volume to obtain the mass of the oil recovered. Next, the mass of the recovery was divided by the original oil in place to obtain the recovery as %OOIP. The hot waterflood recoveries are presented in Table 4.8.

Since pressure drawdown results in a rapid change of phase for both the water and a fraction of the oil, this stage of the experiment will often be refered to as the "flash" or "flashing" process.

4.1.6 Steamflood Recovery as %OOIP

The volumes of steamflood recoveries measured in the sight glass were corrected for water/oil emulsion, and then converted to units of mass. The water/oil emulsion factor as determined from the emulsion test (Section 3.7) was 1.025. The corrected volumes were then multiplied by the density of the oil at sightglass temperature to obtain the mass of the oil recovered from steamflooding. The mass of the oil was then divided by the original mass of the oil in place, to obtain steamflood recovery as %OOIP. The steamflooding recoveries are presented in Table 4.9.

4.1.7 Data Averaging

The recovery results of all the stages of experiments are presented in Table 4.10 in terms of percent recovery as

%OOIP. The results were divided into 4 major groups for averaging purposes. The groups were as follows:

1. High permeability samples in Experimental Type 1.
2. Low permeability samples in Experimental Type 1.
3. High permeability samples in Experimental Type 2.
4. Low permeability samples in Experimental Type 2.

In each of the above groups, the average recoveries for the heat-up, hot waterflooding, pressure drawdown, and steamflooding stages for each type of additive were determined as follows.

In general, the results of the replicate runs for each experimental condition were averaged. Each group included 8 runs prior to averaging (with the exception of group 1 which had 9 runs). The 8 runs consisted of 4 conditions of 2 pairs. After averaging, each group was reduced to 4 sets. Tables 4.11 and 4.12 show the averages for each group. For some runs, however, the data for the repeat run was either not available (due to experimental problems), or available but not recommended for averaging (due to inaccurate measurments taken with a obfuscated water/oil interface in the sightglass). For these samples, which accounted to 7 , the single run data was used rather than the averaged value. These 7 runs were as follows:

Run #19: waterflooding data, Experimental Type 2, CO_2
Run #23: pressure drawdown data, Experimental Type 2, CO_2
Run #6: pressure drawdown data, Experimental Type 2, no-additives
Run #18: pressure drawdown data, Experimental Type 1, CO_2
Run #19: pressure drawdown data, Experimental Type 2, CO_2
Run #10: steamflooding data, Experimental Type 1, nitrogen
Run #10: pressure drawdown data, Experimental Type 1, nitrogen

Since heat-up stage is a highly dynamic thermal process which results in the thermal expansion of the fluids in the pore system, the permeability plays a minor role in recovery, particularly if the range of permeabilities is narrow such as in the present study. It was assumed that the heat-up recovery is a function of the thermal expansion of the oil and water in place and not of the petrophysical properties. Heat-up recoveries for the 16 averages in Table 4.11 ranged from 11.05% OOIP to 20.04% OOIP. The arithmetic mean for the 16 averages was 14.16% OOIP wih a standard deviation of 2.15%. This standard deviation provides a reasonable estimate for the expected experimental error in this type of experiment.

It is reasonable, therefore, to assume that the heat-up recovery for each run (regardless of permeability) is equal to the overall average 14.16% OOIP. Also the experimental error will be formally assumed to be equal to the standard deviation, 2.15%. This experimental error will be assumed to be representative for all stages of the experiment. It follows that, for deviations between recoveries to be considered statistically significant, they must be greater than twice the standard deviation (4.30 %).

The second averaging scheme was a group averaging which included using the overall average of the heat-up stage (14.16 %OOIP), and the pressure drawdown recoveries in Experimental Type 2. In the high and low permeability groups of Experimetnal Type 2, since no waterflood had preceeded the pressure drawdown stage, no additive had been introduced in the sample. Theoretically, the runs with each permeability type (low or high) should produce the same amount of oil since the heat-up recoveries were assumed to be equal (14.16% OOIP). For this reason, the pressure drawdown recoveries in each permeability group of the Experimental Type 2 were averaged, and the average was used for each group. The average pressure drawdown recovery for the high permeability samples was 33.02 %OOIP, and 36.61 %OOIP for the low permeability samples. The summary of the results are presented in Table 4.12.

4.2 PHASE 3: ARTIFICIAL LIVENESS TESTS USING ATHABASCA BITUMEN

Twelve (12) runs were performed in this phase. Six of which used low permeability samples, and six used high permeability samples. The discussions in this section will focus on the calculation of the following values.

1. Irreducible water saturation
2. Original mass of oil in place after oilflood
3. Heat-up recovery as %OOIP
4. Pressure drawdown recovery as %OOIP
5. Steamflooding recovery as %OOIP

4.2.1 Irreducible Water Saturation

Table 4.13 shows the results of this stage of the experiments. The irreducible water saturations were calculated using the procedure used in Phase 2. To avoid repetition, the reader is refered to Section 4.1.1.

Three runs in this phase experienced problems with sightglass interface readings. These were runs #4, #7, and #10. No readings of water/oil interface were taken in these runs, since the sightglass was obfuscated by an oil film.

The averaging procedure used in Phase 2 could not be used in this phase, since more than one type of oil was used. Due to the small data population, the values of the corresponding repeat run was used for each of the above mentioned runs which experienced problems (Runs #4, #7 and #10). For Run #4, the data from Run #3 was used. For Run #7, the data from Run #8 was used, and for Run #10, data from Run #9 was used.

4.2.2 Mass of the Original Oil In Place

The mass of the original oil in place was calculated using the equation used in Section 4.1.2. The density of each type of oil was determined at 80 C as follows. For each oil, a predetermined volume was transferred into a cylinder at 80 C. Next, the dissolved additive in the oil was allowed to evolve by lowering the pressure to atmospheric. Once the additive had completely evolved, the "dead" oil was weighed and the mass was determined. The density of the saturated bitumen was then calculated by dividing the mass of the oil by the equivalent volume of the saturated oil at 80 C. The following densities at 80 C were determined for each oil:

Athabasca bitumen saturated with nitrogen = 0.945 g/cc
Athabasca bitumen saturated with carbon dioxide= 0.891 g/cc

Athabasca bitumen saturated with methane = 0.912 g/cc

The above densities indicate that carbon dioxide has the highest solubility tendencies with the Athabasca bitumen, followed by methane and nitrogen. The above densities were used to calculate the mass of the oil in place for each type of oil. The values are tabulated in Table 4.17

4.2.3 Heat-Up Recovery as %OOIP

The oil recovered by the heat-up stage was measured in the sightglass. The measurement included the dead volumes downstream and upstream of the sample as discussed in Phase 2. Although the volumes of the dead spaces were known, the contribution of the oil in the dead spaces due to thermal expansion was not known. For this reason, an experiment was conducted for each oil, to determine the percent thermal expansion from 80 C to approximately 250 C. The experimental procedure for this test is included in Section 3.6. The results of the tests are presented in Tables 4.14, 4.15, and 4.16. Once the thermal expansions for each oil were determined, the exact volumes due to dead volume thermal expansion were calculated and subtracted from the total heat-up production.

To determine the mass of the heat-up recovery, the densities of the saturated oils at random temperatures were determined using the percent thermal expansions and the density at 80 C. The densities for the Athabasca bitumen saturated with nitrogen, Athabasca bitumen saturated with carbon dioxide, and Athabasca bitumen saturated with methaneare presented in Tables 4.14, 4.15 and 4.16, respectively. The graphical presentations of the densities and the thermal expansion rates for the 3 oils are shown in Figures 4.5 and 4.6.

Since the sightglass temperature during measurement varied from 25 C to 55 C, the densities in Tables 4.14, 4.15 and 4.16 were extrapolated down to 25 C by assuming a linear relationship. The densities were then applied to the volumes of the heat-up recoveries to yield the mass of oil recovered. As shown, all oils seem to indicate out-gassing above the temperature of 215 C. Table 4.17 shows the results of the heat-up recoveries as %OOIP.

4.2.4 Pressure Drawdown Recovery as %OOIP

The volume of the pressure drawdown recoveries as measured in the sightglass were corrected for water/oil emulsion and then converted to mass units. The emulsion correction factor used here was 1.1, as determined in Section 3.7.

Since in the pressure drawdown stage, the pressure was lowered to 2 Mpa, the oil remaining in the sample at the end of the process was considered to be "dead" due to evolution of the gas. The densities of the "dead" Athabasca bitumen, therefore, at the sightglass temperatures were applied to the volumes of recoveries, to yield the mass of oil recovered. The mass of oil was divided by the mass of the original oil in place to yield oil recovery as %OOIP. The values are presented in Table 4.17.

4.2.5 Steamflooding Recovery as %OOIP

The volume of the oil recovered in the steamflood stage which was measured in the sightglass, was corrected for water/oil emulsion. The factor applied here was 1.025 as determined in the emulsion test (Section 3.7). Next the densities of "dead" Athabasca bitumen at varied sightglass temperatures were applied to these volumes, and the mass of the oil recovered was determined. Table 4.17 shows the oil recovered in the steamflood process as %OOIP.

4.2.6 Data Averaging

Table 4.18 shows the percent oil recoveries as %OOIP for all stages in Phase 3. The results of the 12 runs were divided into 2 major groups for averaging purposes. The groups were as follows:

1. High permeability samples in Experimental Type 2.
2. Low permeability samples in Experimental Type 2.

For each type of oil, the results of the replicate runs in Table 4.18 were averaged, and the average values represented the result for each stage. The only exception was pair Runs #3 and #4. Since Run #4 experienced experimental problems in the heat-up stage, the average is reperesented by the result of Run #3. The results of the other stages (pressure drawdown and steamflooding) for Run #4 were not affected by the experimental problem and therefore was used for averaging.

The results of the initial averaging are shown in Table 4.19. The results of the next averaging scheme are presented in Table 4.20. In Table 4.20, the heat-up recoveries in Table 4.19 were averaged for the high and the low permeabilities. The reason for this as discussed in Section 4.1.6, was that the heat-up stage is a highly violent process, where the energy is expended regardless of permeability. Certainly, for the samples used in this study, permeability was not a significant factor in this stage.

4.3 PHASE 4: LIVE CRUDE TESTS USING LLOYDMINSTER CRUDE

The data analysis in this phase was very similar to the data analysis in Phase 2. The only difference was that in Phase 4 "live" Lloydminster oil was used, whereas in Phase 2, "dead" Athabasca was used.

Thirty four (34) tests were performed in this phase, of which two were aborted due to experimental problems after heat-up. The data for the two aborted runs is not included in this report. Of the 32 tests, 16 utilized low permeability samples, while the other 16 utilized high permeability samples. The final results of this phase are presented in Table 4.32. As in Phase 2, discussions include the determination of the following values.

1. Irreducible water saturation
2. Original mass of the oil in place after oilflood.
3. Thermal recovery as %OOIP.
4. Waterflood recovery as %OOIP.
5. Flash recovery as %OOIP.
6. Steamflood recovery as %OOIP.

4.3.1 Irreducible Water Saturation

Distilled water was used to 100% saturate the samples. The technique used to collect and measure the water displaced by the oilflood, was modified after the first 13 runs. The modified technique, as discussed previously (Section 3.5.3), was by the use of a collecting cylinder downstream of the sample. The data analysis procedure for the first 13 runs is, therefore, different from the last 19. The results are presented in Table 4.21.

The calculation of the irreducible water saturations is similar to the calculation used in Section 4.1.1 for Phase 2. To avoid repetition, the calculation procedure is not discussed here.

Experimental problems were encountered during oilflooding to irreducible water saturation for Runs #4, #6, #7, #9, #10, #14, #15, and #16 with the S_{wi} values of 32.15%, 12.30%, 31.49%, 33.77%, 35.22%, 36.01%, 9.21%, and 12.90%, respectively. The experimental problem in most runs was that a clear water/oil interface could not be maitained in the sightglass when taking readings. The original data for the S_{wi} values are included in the Appendix.

Similar to Phase 2, the problem with these runs were the sightglass readings and not an experimental problem with the sample. The remaining stages of the experiments (i.e., pressure drawndown, waterflooding, etc) for these runs were performed without any problems. Therefore, in order to make use of the results of the remaining stages, it was necessary to use average values for the S_{wi}. Three groups of permeabilities were selected that would represent the permeabilities of the 8 problem samples. These were the high, medium, and low groups. The high permeability group consisted of samples ranging in permeability from approximately 1200 md to 2500 md (any sample over 2500 md was not used in this group); the medium permeability group contained samples ranging in permeability from approximately 600 md to 1200 md; and the low permeability group contained samples ranging in permeability from approximately 70 md to 144 md.

For the high permeability group, a total of 6 runs (including 3 problem samples) were included. The problematic runs were Runs #9, #10, and #14 with S_{wi} values of 33.77%, 35.22% and 36.82%, respectively. The average for the 3 runs (excluding the 3 problem runs) was 18.04%. This average value was used for Runs #9, #10 and #14.

For the mid permeability group, 8 runs were included (including one problem run). The problematic run was Run #6, with a S_{wi} of 12.30%. The average for the 7 runs (excluding Run #6) was calculated to be 17.84%, which was used for Run #6.

For the low permeability group, 16 runs were included (including 4 problem runs). The problematic runs were Runs #4, #7, #15, and #16 with values of 32.15%, 31.49%, 9.21% and 12.90%, respectively. The average for the 12 runs (excluding the 4 problem runs) was 21.93%. This value was used for the 4 problem runs.

4.3.2 Mass of the Original Oil In Place

The mass of the original oil in place was calculated using the same procedure as in Phases 2 and 3. Results are presented in Table 4.25.

In the experimental discussions (section 3.6), it was discussed the thermal expansion test was performed for the "live" Lloydminster bitumen. In this section, a discussion on the analysis and the use of that data is provided.

In the thermel expansion test, the solution gas was allowed to evolve completely. The mass of the "dead" oil was then measured. Since the volume of the "live" oil at ambient temperature was known, the density of the "live" oil at ambient temperature was then calculated. The calculated value was 0.837 g/cc. Next the thermal expansion of the "live" oil to 80 C was used to calculate the density of the live oil at 80 C. The live oil density at 80 C was 0.804 g/cc. The density of "live" Lloydminster oil was used to calculate the mass of the original oil in place at 80 C. The values are presented in Table 4.25.

4.3.3 Heat Up Recovery as %OOIP

As discussed in the previous phases, the oil measured in the sightglass during the heat-up stage included oil from both the sample and the dead volume. In order to determine the volume of the oil contributed to the total heat-up recovery as a result of the thermal expansion of the water and oil in the dead volume, the thermal expansion of the "live" Lloydminster oil was determined. The thermal expansions for distilled water at different temperatures were given earlier in Section 4.1.3.

For the "live" oil, the experimental procedure for the thermal expansion test was discussed in Section 3.6. The results of the test are presented in Table 4.23. Figure 4.9 shows thermal expansion of "live" Lloydminster oil graphically. As is shown, the thermal expansion of the "live" Lloydminster oil is fairly linear up to a temperature of about 225 C, after which a steep increase in thermal expansion from 12.70% at 225 C to 22.60% at 250 C is observed. This is indicative of out-gassing.

The thermal expansions at 250 C for both the "live" oil and the water were applied to the dead volumes in the system, and the corrected volumes of the oil expelled from the sample as the result of the heat up were calculated. It should be noted that the thermal expansion test, for which the results are shown in Table 4.23 and Figure 4.7 was performed at a pressure of 10 Mpa. The actual heat-up process, however, was performed at a pressure of 8-9 Mpa (depending on the bubble point pressure of the mixed oil). The higher pressure of the "live" oil increases the temperature at which out-gassing occurs. Therefore, it is very probable that in the actual runs, where the pressure was 1 to 2 Mpa lower than the pressure of the expansion test, out-gassing occured at a lower temperature, resulting in a higher thermal expansion (than 22.6%) at 250 C.

Once the corrected recoveries in terms of volume for the heat-up stage was determined, the mass of the produced oil was determined by applying the density of the live oil (Table 4.24) at sightglass temperature to the corrected volumes.

The sightglass temperature at which oil was collected varied from 25 C to 55 C. Since Figure 4.8 shows a fairly linear relationship between density and temperature, the density of the "live" oil for the actual sightglass temperature was extrapolated between 25 C and 80 C.

Table 4.24 does not show the density of the live oil at 250 C. The reason for this is that since flashing (outgassing) occurred below this temperature, the density could not be determined. However, it is expected that the density after outgassing will increase significantly.

It should be noted that the volume of oil which was collected in the sightglass during the heat-up stage was of basically two types. One was the volume that was produced prior to outgassing, and one that was produced after outgassing. The concern here initially was that in order to properly convert the volume of oil to mass units using the "live" oil densities, the oil in the sightglass need be in a "live" state as well. The oil which was produced after outgassing, was most likely "partially live" (refered to as undersaturated oil). Therefore to accurately calculate the mass of oil in sightglass, one should apply the appropriate density to the correct portion of the oil volume. This, however, was impossible, since neither the portions of the produced volume before and after outgassing, nor the liveness of the oil after outgassing was known. The difference between "live" oil density and "dead" oil density for the range of sightglass temperatures suggested that based on a 50/50 breakdown of the production volume before and after outgassing, a 3% error would be introduced by using the "live" oil density .

The "live" oil densities were, therefore, used to calculate the mass of the oil recovered in the heat-up stage. Once the masses were determined, the heat-up recoveries as %OOIP were determined by dividing the masses by the original mass of the oil in place. The values are presented in Table 4.25.

4.3.4 Waterflood Recovery as %OOIP

The volume of oil recovered in the waterflooding stage was corrected for water/oil emulsion and then converted to units of mass. The emulsion correction factor used in this phase was the same as in Phase 2 (Section 4.1.4).

To convert the volume of oil produced to mass units, the average "live" and "dead" oil densities were used. The reason for this, as mentioned earlier, was that, since the oil was flashed at 250 C during the heat-up stage, the oil that was produced in the waterflood was "partially live". Since the degree of liveness was not known, the average densities were used. The average densities up to a temperature of 225 C were calculated (Table 4.26). Average densities for the range of sightglass temperatures (25 C to

55 C) were extrapolated from 80 C.

The mass of the recovered oil due to waterflooding was then divided by the mass of the original oil in place to yield the waterflood recovery as %OOIP. The data is presented in Table 4.27.

4.3.5 Pressure Drawdown Recovery as %OOIP

The volume of the pressure drawdown recoveries as measured in the sightglass were corrected for water/oil emulsion and then converted to units of mass. The emulsion correction factor used here was 1.1 (the same as used in Phase 2, Section 4.1.5). Although the results of the Athabasca emulsion test were used for Lloydminster oil, published data show that the emulsion factor applies for both types of oil. In particular, a recent study by Chung and Butler showed that for Cold Lake (Lloydminster) oil, a water/oil ratio of 0.1 was found in a steam run.

It was discussed earlier that during outgassing of the "live" oil in the heat-up stage, the produced oil during the waterflood stage still contained dissolved gas . In the pressure drawdown stage, since pressure was reduced to 2 Mpa which is significantly below the bubble point pressure of the oil, the oil produced during this stage was most likely a "dead" oil. For this reason when the volumes of pressure drawdown recoveries were converted to mass units, the densities of the "dead" Lloydminster crude at the appropriate sightglass temperatures were used. Figure 4.9 shows the "dead" Lloydminster densities.

The mass of the oil calculated for each sample was then divided by the mass of the original oil in place to yield the pressure drawdown recovery as %OOIP. The data is shown in Table 4.28.

4.3.6 Steamflood Recovery as %OOIP

The volume of recoveries in the steamflood measured in the sightglass was corrected for water/oil emulsion, and then converted to units of mass. The procedure was the same as in Phases 2 and 3. It should be noted that the densities used to convert volumes to units of mass were the "dead" oil densities, since the oil produced was at a pressure of 2 Mpa. The data is presented in Table 4.29.

4.3.7 Data Averaging

Table 4.30 shows a summary of the recoveries as %OOIP for all four stages in the experiments. For averaging purposes, the 32 runs were divided into 4 major groups as in Phase 2. These groups were:

1. High permeability samples in Experimental Type 1
2. Low permeability samples in Experimental Type 1
3. High permeability samples in Experimental Type 2
4. Low permeability samples in Experimental Type 2

The recoveries for the replicate runs were averaged. The only average that did not use the result of both runs was the pair of Runs #9 and #10. Since the result of the heat-up recovery for Run #9 was not available (due to experimental problems), only the result of Run #10 was used. The results of this first round of averaging are shown in Table 4.31.

A further averaging of the heat-up recoveries in Table 4.32 was performed. Since the quality of oil (i.e bubble point pressure) and the pore pressure directly affect the volume of the oil produced during the heat up stage, 3 averages for the heat-up stage were determined. Each value represents a bubble point pressure and a pore pressure in the heat-up stage. The first was the average of the no-additives, nitrogen , and the methane runs. These were for both types of permeabilities. The bubble point and pore pressure for the 12 values in Table 4.31 were similar. The second was the average for carbon dioxide runs in Experimental Type 1, for both permeabilities. The bubble point pressure and the pore pressures were lower than the other runs. The third was the average of the carbon dioxide runs in Experimental Type 2, both permeability types. The bubble point pressure was the same as in the first case, but the pore pressure was higher.

Average values for the pressure drawdown recoveries for the no-additive, nitrogen, and methane runs in Table 4.31 were further averaged in Table 4.32. The justification for this was that the heat-up recoveries were the same (as a result of averaging), and that no additives were added in the pressure drawdown stage in Experimental Type 2. Theoretically then, similar recoveries are expected in the pressure drawdown stage given that the same type of oil is used. For the carbon dioxide runs in Experimental Type 2, the two averages in Table 4.31 were also further averaged.

5. DISCUSSION OF RESULTS

All results should be considered in the context of the expected accuracy of the experimental procedure. In Section 4.1.7,, based on a detailed analysis of the heat up recovery of Athabasca bitumen, the experimental error was established as (+/-) 2.15 %OOIP. This value is used throughout the discussions, regardless of the process or the type of oil used.

In order for two recoveries to be significantly different, they must differ by at least 4.30 %OOIP. Differences of less than this could be entirely due to experimental error. The use of the term "significant difference" in the following discussions is based on differences larger than 4.30 %OOIP.

Due to the volume of data involved, the discussions in this section are divided into subsections pertaining to each process, and further to each experimental type and permeability type.

5.1 PHASE 2: DEAD ATHABASCA BITUMEN TESTS

The results of this phase are tabulated in Table 4.12. To compare the effect of the additives on recovery, all runs with additives, were compared with the result of the no-additive runs. The results of the no-additive runs were taken as the baseline recovery. The difference in recovery between the baseline runs and the additive runs are shown in Table 5.1.

5.1.1 Heat up recovery

The average recovery for the heat-up stage for Phase 2 was found to be 14.16 %OOIP. This value represents the average recovery for the heat-up stage for both types of permeabilities.

The Athabasca bitumen thermal expansion when heated from 80 C to 250 C, was approximately 12.67%. The thermal expansion of the 3% solution of brine (which occupied the pore space as the irreducible water saturation), was approximately 17.80%. The thermal expansion of distilled water, which also occupied the pore space as the irreducible water satuartion in some of the runs, was approximately 21.27%.

Table 4.6 showed the heat-up recoveries for each run. The difference in heat up recoveries between the runs seem to indicate a mechanism involved with heating the irreducible water. Depending on the distribution of the irreducible water in the core, the expanded water either gets produced or it causes oil to be produced.

Based on the thermal expansions of the bitumen and water, certain limits can be established. If water expansion does not displace oil, then the expansion of oil (approximately 12.67%), establishes the lower limit. If on the other hand, water expansion does displace oil, then the thermal expansion of water (approximately 21.27%) establishes the upper limit.

It stands to reason that a heat-up recovery less than the lower limit (12.67 %) or higher than the higher limit (21.27 %) is associated with experimental error. Table 4.6 indicates that approximately 8 runs resulted in recoveries less than the lower limit and 3 runs higher.

A high degree of consistency was observed between the replicate runs for the high permeability samples than for the low permeability samples. As shown in Table 4.6, 5 out of 8 sets of runs in the high permeability group, indicated good repeatability, while in the low permeaiblity group only 4 were considered to be in good agreement.

5.1.2 Waterflooding Recovery

5.1.2.1 High Permeability Samples

The average waterflood recovery for the baseline (no-additive) case was 31.60% OOIP. The average waterflood with additives recoveries were 33.22% , 37.80% and 30.34% OOIP, for nitrogen, carbon dioxide and methane, respectively.

This indicates that for the high permeability samples, nitrogen and methane when injected with water, do not introduce any added mechanisms than what is already present with water alone. Carbon dioxide which has been shown (Svreck and Mehrotra) to be highly soluable in hydrocarbons, seem to be more effective. There are basically two possible scenarios for the behavior of nitrogen and methane. The first is that since water and gas were injected at the top of the sample, they may have segregated. If water was in front of the gas (in contact with the hydrocarbon) then it was not saturated with the additive. At breakthrough, the additive basically followed the path of the water, resulting in little or no dissolution. The second scenario is that the conditions for miscibility may not have been present for solubility of nitrogen and methane with oil, and the gas behaved more like an immiscible fluid. The conditions refered to here may be that since gas was injected from one end of the core and traversed a fairly short distance to the exit end of the core, the flowrates may not have been sufficiently low to allow dissolution. In both of these scenarios, because of the high permeability of the samples and the networking of the matrix, the capillary pressures were not effective in holding the gas back and allowing it to mix with the oil.

A possible reason for the behaviour of carbon dioxide is that it is more soluble in water than the other two gases. This may have allowed it to be more effective in contacting the oil.

5.1.2.2 Low Permeability Samples

The waterflood recovery results for the low permeability samples as shown in Table 4.12 and 5.1 showed that all additives resulted in significant improvement over the baseline recovery. In contrast to the high permeability results, the carbon dioxide was least effective in improving recovery. It should be noted that the result of the carbon dioxide run in Table 4.12 is based on the result of only one run, whereas the others are the average of two runs. The carbon dioxide result, therefore, contains more uncertainty.

The higher recoveries associated with the additives runs indicate that gaseous additive can in general be effective given the appropriate conditions. Methane seem to be the most effective additive and the appropriate condition (aside from miscibility conditions of pressure and temperature) seem to be lower permeability. Higher capillary pressures in the lower permeability samples may be the phenomenon that allows the gas to dissolve more effectively in the oil, increasing its mobility and resulting in higher recoveries.

Hot waterflooding with carbon dioxide resulted in approximately 13% lower recovery than waterflooding with nitrogen. This is an unusual result, since earlier it had been established that in lower permeability samples, conditions for dissolution of gas are more conducive than in higher permeability samples, and that carbon dioxide has the highest solubility. A possible explanation as noted earlier is that the carbon dioxide result is based on a single run whereas the nitrogen result is based on an average of two runs. There are also reasons to believe that the waterflood recovery for Run #11 (run with nitrogen additive) is too high. The reason being that the total recovery for this run was 94.26 %OOIP (Table 4.10) which was uncharacteristically high when compared with the nitrogen runs in its group. This may have been caused by an interface reading problem in the sightglass. However, since there were no obvious experimental difficulties observed during this run, the data can not be discounted.

5.1.2.3 Comparison of Waterflooding Results Between the Two Permeability Types

Table 4.12 indicates that hot waterflooding without additives results in fairly similar productions regardless of permeability. In general, with the exception of a possible erroneous carbon dioxide result for low permeability samples, the recovery is significantly improved by additives in low permeability samples, but not in high permeability samples.

The earlier conclusion, that conditions for dissolution of gas in oil while injected with water are more conducive in lower permeability samples than in the higher permeability samples, stems from the fact that in the higher permeability samples, significant differences in recoveries were found for only the carbon dioxide runs, while in the lower permeability samples improved recoveries were found for all the additives.

5.1.3 Pressure Drawdown Recovery

The pressure drawdown process is inherently violent. As the pressure drops, two phase changes occur. Firstly, if the oil is "live", gases will begin to evolve; secondly, once the boiling point of water is reached, the water in the core will evaporate. Since both of these processes involve large volume changes, the result of pressure drawdown is a rapid disruption of the fluids in the core.

Flashing of water is also a non-uniform process; the time when water changes phase is determined by the pressure history at a point. Local pressure variations exist due to microscopic heterogeneties in the flow path. Flashing of water may therefore occur more readily in some locations than in others. This phenomena is further complicated when two types of water are present, namely the connate water and the flood water.

5.1.3.1 Experimental Type 1

5.1.3.1.1 High Permeability Samples

The results are shown in Tables 4.12 and 5.1. It should be noted that the results for the nitrogen and carbon dioxide runs are based on a single run, while the results for methane are the average of two runs.

The results confirm the fact that in the higher permeability samples, gases, particularly those with high solubility tendencies such as carbon dioxide and methane, did not seem to dissolve in the oil effectively in the oil when injected with water. The results here suggests the following scenarios. The flashing of water with no additives, resulted in an effective displacement of oil, with a low degree of fingering and channelling. On the other hand, the presence of undissolved gases at the time of pressure drawdown caused steam channelling through the gas phase. This resulted in a poor displacement efficiency.

5.1.3.1.2 Low Permeability Samples

The pressure drawdown recoveries for nitrogen and carbon dioxide showed a significant improvement. This indicates that the additives were instrumental in recovering more oil from the low permeability samples. The mechansim identified here is perhaps some degree of gas evolution (gas dissolved in by waterflood) from oil. This causes oil to be displaced, along with a lower degree of steam channelling as compared with the high permeability samples. The lower recovery associated with methane is probably due to the fact that there was much less oil in place after waterflooding.

No explanation can be offered for why nitrogen and carbon dioxide runs resulted in similar recoveries in the pressure drawdown stage, since nitrogen is considered to have low solubility.

5.1.3.1.3 Comparison of Pressure Drawdown Results Between the two Permeability Types in Experimental Type 1

Table 4.12 shows that the high permeability samples with no additives have a significantly greater recovery than the low permeability samples with no additives. This comparison is valid since the average waterflood recoveries before the pressure drawdown were very similar for the two cases.

The role of additives in the pressure drawdown stage between the two types of permeability is more difficult to explain. With the result of the baseline recoveries in the low and high permeability samples, the question becomes which plays a more important role in the pressure drawdown recovery, dissolution or permeability?

For the high permeability samples, the additives appear to retard production, most likely because of the low capillary pressures, allowing the promotion of channelling. While for low permeability samples, capillary pressures suppress channelling and allow dissolution to recover more oil. This implies that gas additives may selectively improve flash production based on the permeability of the reservoir.

5.1.3.2 Experimental Type 2

5.1.3.2.1 High Permeability Samples

The average pressure drawdown recovery for the high permeability samples in Experimental Type 2 was 33.02 %OOIP (Table 4.12). This was the average of 7 runs. It should be noted that the carbon dioxide runs in Table 4.11, showed an uncharacteristically low value (18.72 %OOIP). This value cause the average value to decrease, since the other average pairs were in the mid to high 30's (35.58% to 39.42 %). However, since the 18.72 % was the result of two fairly repeatable values (22.97% and 14.46%), they were utilized in the averaging.

5.1.3.2.2 Low Permeability Samples

The average pressure drawdown recovery for the low permeability samples in Experimental Type 2 was 37.61 %OOIP (Table 4.12). Again this value was the result of averaging 7 runs.

5.1.3.2.3 Comparison of Pressure Drawdown Results Between the two Permeability Types, Experimental Type 2

The data showed that the lower permeability samples resulted in higher recoveries in the pressure drawdown stage of Experimental Type 2, than in the higher permeability samples. The difference between the two values (33.02 %OOIP vs 37.61 %OOIP), is statistically significant.

5.1.3.3 Comparison of Pressure Drawdown Results Between Experimental Types 1 and 2

Since the pressure drawdown recovery of Experimental Type 2 did not contain any additives, only those runs in Experimental Type 1 without additives was compared here. In Experimental Type 2, before pressure drawdown, the sample was at irreducible water saturation, while in Experimental Type 1, in addition to the irreducible water saturation, some mobile water was also present due to hot waterflooding.

In the earlier discussions, it was established for Experimental Type 1, that the higher permeability samples resulted in higher recovery, and from Experimental Type 2, it was established that the opposite was true. This is perhaps the role that mobile water plays for the two permeability types. In other words, mobile water in the higher permeability samples improves oil recovery than in the lower permeability samples.

In the higher permeability samples, the average pressure drawdown recoveries were 27.60 %OOIP for Experimental Type 1, and 33.02 %OOIP for Experimental Type 2. It should be noted that the pressure drawdown in Experimental Type 1, is preceeded by hot waterflooding and hence less oil in place. The results between the two experimental types here are very similar which suggests the importance of higher water saturation in the pressure drawdown stage for high permeability samples. This result indicates that waterflooding with pressure drawdown is a more efficient recovery process than huff-and-puff. Further, the results indicate that the superiority of waterflooding with pressure drawdown improves as the permeability increases.

5.1.4 Steamflood Recovery

Steamflooding followed after a pressure drawdown stage essentially constitutes a stripping process, removing oil from the walls of the pores and perhaps invading adjacent pores. This process would be adversely affected by the existing gas channels, since steam would preferentially follow these paths rather than displacing oil. Additives could augment the stripping process if they dissolve in the oil, causing it to swell into the flow paths, as well as lowering its viscosity.

5.1.4.1 Experimental Type 1

5.1.4.1.1 High Permeability Samples

Both nitrogen and carbon dioxide resulted in significant increases in recovery, while the effects of methane were insignificant. It should be noted that the result for nitrogen, is based on a single run, whereas the others are the average of two runs. The only explanation offered regarding the low steamflood recovery of the methane run as compared to the nitrogen and carbon dioxide, is the distribution of oil within the pore spaces of the rock. After the violent process of flashing during the pressure drawdown stage, oil may have distributed unfavorably for displacement, when compared with the runs that used other additives.

In general, with the exception of methane, additives seem to help in stripping the oil from the walls of the pores during steamflooding in high permeability samples.

5.1.4.1.2 Low Permeability Samples

All three additives resulted in significantly reduced recoveries. This seems to indicate that additives did not contribute to an effective stripping of the oil in place for the low permeability samples. This should, however, be examined in the context of how much oil was left in place when steamflooding was performed. For the runs with no additives, the sum of the recoveries in the heat up, waterflooding and pressure drawdown stages totaled 58.81 %OOIP, leaving 41.19 %OOIP in place. For the nitrogen, carbon dioxide, and methane runs, however, recoveries totaled to 74.01%, 70.73% and 75.51% OOIP, leaving 25.99%, 29.27%, and 24.49% OOIP in place, respectively. This clearly indicates that in the no additive case, there was significantly more oil in place than in the runs with additives. Therefore, no conclusions can be drawn without prejudicing the results, regarding the effect of additives on stripping mechanism in the low permeability samples. However, it can be concluded that there was no preference between the types of additives for the steamflood.

5.1.4.1.3 Comparison of Steamflooding Results Between the two Permeability Types, Experimental Type 1

Steamflooding seems to be slightly more effective in the higher permeability samples than in the lower permeability samples. This was rather a difficult conclusion to make since the amount of original oil left in place after pressure drawdown varied from sample to sample. Therefore, direct comparison of the results between the two permeability types is difficult. The conclusion, however, is based on a comparison of the difference between the amount of original oil left in place and the amount recovered in steamflooding. For example, in the high permeability runs with nitrogen as the additive, there was 33.77% OOIP left in place after pressure drawdown. Of this, 17.02% was recovered in the steamflood. On the other hand, in the low permeability runs using the same additive (nitrogen), there was 25.99% OOIP left in place, of which only 4.80% was recovered. The difference here between the amount of oil in place is 7.78% OOIP, while the difference in the oil recovered is 12.22% OOIP.

This was also true for carbon dioxide as well. There was approximately 1.99% more oil in place in the high permeability runs than in the low permeability runs. However, the oil recovered in the steamflood in the high permeability runs was 14.94% OOIP while in the low permeability runs it was only 8.72%, a difference of 6.22%. When the differences in the amount of the oil left in place and the amount of oil recovered in the steamflood are compared, it can be concluded that steamflooding was more effective in the high permeability samples.

For the no additive run, there was approximately 14.55% more oil in place in the low permeability runs after the pressure drawdown than the high permeability runs. But the difference in recovery between the two permeability types was only 3.11% in favor of the low permeability runs. Here the differecne in oil recovery between the two permeability types is much lower than the difference in the original oil in place, which indicates that the higher recovery observed for the low permeability samples can be attributed to the higher amount of oil present at the start of the steamflood.

5.1.4.2 Experimental Type 2

5.1.4.2.1 High Permeability Samples

A comparison of the results in Table 4.12 between the baseline run recovery and the additives runs indicate that additives were somewhat instrumental in stripping the oil from the walls of the pores. However it should be noted that the difference in recovery between the no additive run and nitrogen and or carbon dioxide runs were within the experimental error, and that among the additives, carbon dioxide seemed to be the only efficient additive.

5.1.4.2.2 Low Permeability Samples

The results are within the experimental error and are therefore, considered as similar. This indicates that additives did not improve in the recovery in the low permeability samples of Experimental Type 2.

5.1.4.2.3 Comparison of Steamflooding Results Between the Two Permeability Types, Experimental Type 2

In the Experimental Type 2, steamflooding in the low permeability runs seemed to be more efficient than in the high permeability runs. The averaged results in Table 5.1 show that although there was less oil in place in the low permeability runs after the pressure drawdown stage, there was more oil recovered in the steamflooding stage. In particular, in the high permeability samples, there was an average of 52.37% OOIP in place after pressure drawdown, and the range of oil recovered in the steamflooding varied from 6.85% to 11.77%. In the low permeability runs, however, there was an average of 48.23% oil in place after pressure drawdown, and the oil recovered in the steamflood varied from 13.49% to 16.91%.

5.1.4.3 Comparison of Steamflooding Results Between Experimental Types 1 and 2

With the exception of the methane run, high permeability samples resulted in higher steamflood recoveries in Experimental Type 1 than in Experimental Type 2. This was true even though in Experimental Type 2 there was significantly more oil left in place after pressure drawdown stage than in Experimental Type 1. The average oil remaining in high permeability runs for Experimental Type 2 after pressure drawdown was 52.82%, while for Experimental Type 1, it varied from 26.64% to 32.99%. This indicates that there was almost twice as much oil in place in runs using Experimental Type 2 than Experimental Type 1. Yet the steamflood recoveries in Experimental Type 1 were higher.

This clearly shows that in the high permeability samples, waterflooding before pressure drawdown is a very effective means of achieving a more efficient steamflooding recovery.

Additives in waterflooding did not seem to be very effective in improving steamflooding recovery. This was indicated by comparing the results of the no additive runs and the additives runs between the two experimental types.

The speculated mechanism for the higher permeability samples in Experimental Type 1, is that the mobile water which was added during the waterflood, when flashed in the pressure drawdown stage, creates a more violent reaction which helps in mobilizing the trapped oil in the smaller pore throats. This leads to a more efficient stripping mechanism than in Experimental Type 2 (where only the irreducible water is flashed).

In the low permeability samples, no conclusion can be drawn with regards to whether waterflooding improved steamflooding recoveries. The reason being that in Experimental Type 1 as compared to Experimental Type 2, where there was less oil after pressure drawdown stage, less oil was recovered. For this reason, it is not clear if the additional oil produced in Experimental Type 2 was the result of more oil in place or because of some other reasons.

5.1.5 Summary of Conclusions for Phase 2

1. The overall average heat-up recovery for all samples from a temperature of 80 C to 250 C was 14.16 %OOIP.

2. Fluids used in this phase had the following thermal expansions from 80 C to 250 C which were experimentally determined:

   Athabasca crude oil: 12.67%
   3% NaCl brine : 17.80%
   Distilled water : 21.27%

3. The maximum theoretical heat-up oil recovery as calculated by the fluids thermal expansion was 19.00 %OOIP, and the minimum was 12.67 %OOIP. The maximum was calculated assuming that irreducible water thermal expansion caused only oil expulsion, and the minimum was calculated assuming irreducible water thermal expansion caused no oil expulsion.

4. Based on the maximum and the minimums above, the heat-up recoveries for the individual runs which were higher than the minimum value of 12.67 %OOIP, indicated that oil recovery depends on the distribution of irreducible water saturation. That is the distribution of irreducible water has a direct effect on how much of the expanded water will be produced and how much of it will cause oil to be produced.

5. No major differences in waterflood recoveries were observed in the high permeability samples when additives were added to water. Therefore, gaseous additives did not seem to play an important role in waterflood recovery in high permeability samples, suggesting very little if any dissolution of additives into oil.

6. In the low permeability samples, becauses of a high oil recovery by waterflooding with CH4, additives with waterflooding seem to play an important role, suggesting some (degree not knowe) dissolution of additives into oil.

7. Gaseous additives improve waterflood recovery when they are dissolved in the oil, otherwise waterflood recovery is not affected by the addition of additives.

8. Dissolution of additives into oil when added during waterflooding seem to be a function of permeability of the rock. The low permeability samples seem to be more conducive to higher degree of dissolution than the higher permeability rocks. The mechanism attributed to here is perhaps the higher capillary pressure phenomenon associated with the

lower permeability samples.

9. In the high permeability samples, non-dissolved additives left in place by waterflood with additives seem to adversly affect oil recovery in pressure drawdown stage. The unfavorable mechanism identified here seem to be the channelling of undissolved additives when the expansion occurs as a result of pressure drawdown. Therefore, if additives are not going to be dissolved in the oil, it is perhaps better not to be added.

10. In the low permeability samples, dissolution of additives into oil by waterflooding (with additives) seem to improve oil recovery in pressure drawdown. The mechanism seem to be the evolution of dissolved additives from the oil when the pressure is drawn down, which causes additional drive to mobilize oil left in place. This also contributes to a lesser degree of gas and steam channelling.

11. High permeability samples seem to displace more oil in pressure drawdown after waterflooding (with no additives) than low permeability samples.

12. In (10) above, dissolution of additives in oil was identified as the main factor in a more efficient oil recovery in pressure drawdown stage, and in (11) high permeability was the main factor. It would seem that the combination of the two would result in the most efficient oil recovery mechanism. That is highest oil recoveries in pressure drawdown stage may be expected, if dissolution of additives into oil (by waterflooding or else) in high permeability samples is achieved.

13. When pressure drawdown was performed at irreducible water saturations (no waterflood), low permeability samples recovered slightly more oil in pressure drawdown stage than high permeability samples. However, since the difference was very small, it can be concluded that permeability does not effect pressure drawdown recovery if it is not followed by waterflooding.

14. In high permeability samples, pressure drawdown immediatly after heat-up (flashing of irreducible water saturation), yielded approximately the same amount of oil as waterflooding with or without additives after heat-up. In the other words, waterflooding before pressure drawdown is an important stage in dramatically improving the ultimate oil recovery.

15. Steamflood recoveries after pressure drawdown stage is mainly a function of the oil left in place (due to the violent action caused by flashing of water).

16. Steamflood recoveries which followed waterflood and pressure drawdown were slightly higher in the higher permeability samples. On the other hand, steamflood recoveries which followed pressure drawdown only, were higher in the lower permeability samples.

17. Additives which were added with steam in steamflooding, improved oil recoveries by stripping action in high permeability samples. In the low permeability samples, on the other hand, additives did not particulary improve recoveries.

5.2 Phase 3: ARTIFICIAL LIVENESS TESTS

The results of the artificial liveness tests are tabulated in Table 4.20. Table 5.3 presents the results in the form of comparisons with the baseline runs. Since all runs were performed with additives, the baseline run was taken as the run in Experimental Type 2 with no additive of Phase 2 (Table 5.1).

5.2.1 Heat Up Recovery

In all cases, a significant improvement in heat up recovery was observed regardless of oil or permeability type.

5.2.1.1 Athabasca bitumen saturated with Nitrogen

The average heat up recovery for this oil was 24.15 %OOIP. The thermal expansion test showed that the thermal expansion of Athabasca bitumen saturated with nitrogen from a temperature of 80 C to 194 C was 9.94 %. The thermal expansion to 250 C was not available due to experimental difficulties. However, a thermal expansion of approximately 22 % from a temperature of 80 C to 250 C was estimated by a linear extrapolation. Since the thermal expansion for the 3% brine was experimentally determined to be 17.80%, the average heat up recovery of 24.15 % indicated that the thermal expansion of the irreducible water saturation did not result in production of water. The difference in the maximum oil recovery (17.8%), assuming no water production during heat up, and the actual oil recovery is likely associated with outgassing.

5.2.1.2 Athabasca bitumen saturated with Carbon Dioxide

The average heat up recovery for this type of oil was 42.18 %OOIP. The thermal expansion of the "live" oil from a reference temperature of 80 C to 211 C was experimentally determined to be 26.20%. The results also showed that from a temperature of 211 C to 250 C, a very high volumetric expansion (3.5 times the original volume) took place. This was indicative of outgassing above a temperature of 211 C. With 42.18 %OOIP oil recovery, and approximately 350% volumetric expansion by the oil, it is reasonable to assume that when outgassing by the oil occurred, most of the solution gas channelled and was produced. The outgassing, although resulting in a significant gas production, seems to have been quite effective in increasing oil recovery during the heat up stage. Since outgassing occurred, it is difficult to speculate on the effect of irreducible water saturation on heat up recovery.

5.2.1.3 Athabasca bitumen saturated with Methane

The average heat up recovery for this type of oil was 27.68 %OOIP. The thermal expansion of the "live" oil from a reference temperature of 80 C to 190 C was experimentally determined to be 21.58%. From a temperature of 190 C to 216 C, the expansion increased to 38.56%, and from 216 C to 250 C, it increased to 254%. This was indicative of the outgassing phenomenon. The heat up oil recovery of 27.68% and the thermal expansion of 254% by the oil, provides sufficient proof that solution gas broke through (channelled) when outgassing occurred. Since outgassing occured, it is difficult to speculate on the influence of the irreducible water saturation on heat up recovery.

5.2.1.4 Comparison of the Heat Up Recovery Results Between the Types of Oils

The study done by Svrceck and Mehrotra, showed that carbon dioxide has high solubility in Athabasca bitumen and causes high viscosity reductions, whereas methane has intermediate and nitrogen has quite low solubility. The results of the thermal expansion tests in the present study from a reference temperature of 80 C to 250 C seem to confirm these results. The thermal expansion for the Athabasca bitumen saturated with nitrogen was the lowest with 22%, followed by Athabsca saturated with methane with 254%, and the highest was the Athabasca saturated with carbon dioxide with 350%. The volumetric expansions determined here show the degree of solubility of the additive in Athabasca.

The results of the heat up recoveries for the three artificial "live" oils showed that the Athabasca bitumen saturated with carbon dioxide resulted in the highest recovery. The thermal expansion test for the three saturated oils also showed that outgassing was most significant in the Athabasca bitumen saturated with carbon dioxide. This suggests that outgassing is an effective mechanism in improving oil recovery during heat up production. In the scope of this study, dissolved carbon dioxide in Athabasca bitumen seem to be the most effective additive to enhance heat up recovery. The mechanism for this may be viscosity reduction caused by high solubility of carbon dioxide in Athabasca bitumen. In other words, low viscosity "live" oil as compared to high viscosity "live" oil, is less conducive to solution gas channelling during the outgassing process.

5.2.2 Pressure Drawdown Recovery

5.2.2 High Permeability Samples

The pressure drawdown recovery for the Athabasca bitumen saturated with nitrogen was 34.97 %OOIP, for the Athabasca bitumen saturated with carbon dioxide was 45.44 %OOIP, and for the Athabasca bitumen saturated with methane was 54.49 %OOIP.

Dissolved nitrogen did not result in a significant change in pressure drawdown recovery. This is reasonable in light of the fact that nitrogen has a low solubility in oil. The recovery of the Athabasca bitumen saturated with nitrogen was the lowest among other oils, even though there was more oil left in place after heat up recovery than the other oils.

Both carbon dioxide and methane led to significant improvements in recovery during the pressure drawdown process, despite the fact that significantly less oil remained after the heat up process. The relative performance of these two types of oil (methane better than carbon dioxide) may be due to the fact that much more oil was present after the heat up in the case of methane. There does not seem to be a significant difference in the overall recoveries after pressure drawdown stage between the Athabasca bitumen saturated with carbon dioxide and Athabasca bitumen saturated with methane. Total recovery after pressure drawdown for Athabasca bitumen saturated with carbon dioxide was 87.62 %OOIP, while for Athabasca bitumen saturated with methane was 82.17% OOIP. Low heat up recovery in Athabasca bitumen saturated with methane is compensated for in the pressure drawdown stage. Therefore, in the case of carbon dioxide and methane, pressure drawdown recovery seems to be directly proportional to the oil left in place.

The effect of solution gas which remained in the sample as a third phase, after outgassing in the heat up stage, is not known. This gas (for carbon dioxide and methane) may have contributed to production by providing drive mechanism as it expanded when pressure was lowered to steam pressure.

5.2.2.2 Low Permeability Samples

The pressure drawdown recoveries for the different "live" oils in the low permeability samples followed the same trend as in the high permeability samples. The lowest recovery (27.69% OOIP) resulted from the Athabasca bitumen saturated with nitrogen, and the highest (44.30% OOIP) from the Athabasca bitumen saturated with methane. Pressure drawdown recovery for Athabasca bitumen saturated with carbon dioxide was 37.99% OOIP. This confirms the earlier conclusion that dissolution of gases with high solubility tendencies improves pressure drawdown recovery.

Nitrogen resulted in a significant by lower recovery relative to the baseline case. This was probably due to gas channels which formed during the heat up stage. The carbon dioxide saturated oil performed similar to the baseline case, while the methane oil had significantly more production.

The difference in pressure drawdown recovery between Athabasca bitumen saturated with carbon dioxide and Athabasca bitumen saturated with methane is most likely due to the amount of oil left in place after heat up recovery. With the Athabasca bitumen saturated with carbon dioxide, there was 57.82% OOIP oil left in place, while for the Athabasca bitumen saturated with methane there was 72.32% OOIP. The cumulative recovery then for the "live" Athabasca carbon dioxide bitumen after heat up and pressure drawdown was 80.17 %OOIP and for the Athabasca bitumen saturated with methane was 71.98 %OOIP. This leads to the conclusion that the evolution of dissolution of gas in bitumen is an important mechanism in pressure drawdown recovery. Furthermore, the presence of a low solubility gas (nitrogen) apprears to be detrimental in the pressure drawdown process.

5.2.2.3 Comparison of Pressure Drawdown Recovery Between the Low and the High Permeability Samples

Higher permeability samples had higher oil recoveries in the pressure drawdown stage than the lower permeability samples. This was consistent for all three types of "live" oils.

5.2.3 Steamflooding Recovery

5.2.3.1 High Permeability Samples

The highest steamflooding recovery (7.12% OOIP) was obtained with the Athabasca bitumen saturated with nitrogen, and the lowest recovery was obtained with the Athabasca bitumen saturated with methane. The results from the Athabasca bitumen saturated with carbon dioxide and the Athabasca bitumen saturated with methane were very similar. The higher recovery from the Athabasca nitrogen is probably due to the higher percentage of oil left in place after the heat up and the pressure drawdown stages. This is based on the fact that nitrogen solubility in Athabasca oil is very low, and that after the pressure drawdown stage most of the dissolved nitrogen would be evolved. Therefore the higher steamflood recovery from the Athabasca is not attributed to dissolution effect, but rather to how much oil was left in place. It is concluded from the results that in steamflood recovery after pressure drawdown stage, the type of additive is not particularly important in influencing recovery. Although, in the case of methane, recovery actually deteriorated significantly during steamflooding. This may, however, have been due to the low amount of oil in place after the pressure drawdown process.

5.2.3.2 Low Permeability Samples

Steamflood recoveries in low permeability samples were fairly similar regardless of the type of the oil, and all showed a significant reductions in recovery relative to the baseline case.

5.2.3.3 Comparison of Steamflood Recoveries Between High and Low Permeability Samples

Low permeability samples appear to have significant effect in lowering steamflood recovery for oils which are presaturated with the additives. In the case of high permeability samples, only methane saturated oil showed a significant effect (lowering recovery) over "dead" Athabasca bitumen.

5.2.4 Summary of Conclusions for Phase 3

1. The average heat up recovery for the runs that used Athabasca bitumen saturated with nitrogen was 24.15 %OOIP, for the runs that used Athabasca bitumen saturated with carbon dioxide was 42.18 %OOIP, and for the samples that used Athabasca bitumen saturated with methane was 27.68 %OOIP.

2. Thermal expansion for the live oils used (from a reference temperature of 80 C to 250 C) was as follows:

Athabasca bitumen saturated with nitrogen :	22%
Athabasca bitumen saturated with carbon dioxide :	350%
Athabasca bitumen saturated with methane :	254%

3. The above volumetric thermal expansions mainly indicated the degree of outgassing of the oil, which indicated the ability of the gas to dissolve in the Athabasca bitumen. The results showed that among gases tested, nitrogen with 22% expansion was the least solubale, while CO2 and CH4 with 350% and 254% expansion respectively, had much higher degree of solubility.

4. Outgassing by live oil which resulted from heating up, improved oil recovery in the heat up process.

5. CO2 was particularly an effective additive in the outgassing process during heat up stage.

6. Although methane had lower outgassing as compared to carbon dioxide, nevertheless, it had very high outgassing tendencies. However, the oil recovery in heat up stage for Athabasca bitumen saturated with methane was much lower than Athabasca bitumen saturated with carbon dioxide. This suggest that in addition to outgassing process, the right type of additive to use for dissolution in bitumen is very important to reduce channelling.

7. High oil recovery with Athabasca bitumen saturated with carbon dioxide is attributed to low degree of channelling by carbon dioxide when it flashes. The low degree of channelling is caused by greater viscosity reduction of the live oil with the addition of carbon dioxide.

8. Dissolution of gaseous additive in bitumen was effective in improving pressure drawdown recovery. This was concluded by comparing the results of pressure drawdown recoveries between Athabasca bitumen saturated with nitrogen and Athabasca bitumen saturated with carbon dioxide or methane.

9. The highest pressure drawdown recovery resulted from the Athabasca bitumen saturated with methane. The next highest resulted from the Athabasca bitumen saturated with carbon

dioxide, and the lowest from the Athabasca bitumen saturated with nitrogen.

10. In pressure drawdown, unlike heat up stage, the type of additive was not an important factor in oil recovery, as long as it had medium to high solubility in the bitumen. This was suggested by the high oil recoveries resulting from pressure drawdown of the Athabasca bitumen saturated with carbon dioxide and methane.

11. The high and low permeability samples showed very consistent results of pressure drawdown recoveries between the three types of live oils tested. Athabasca bitumen saturated with methane had the highest recovery, followed by Athabasca bitumen saturated with carbon dioxide, followed by Athabasca bitumen saturated with nitrogen.

12. The high permeability samples consistently resulted in higher pressure drawdown recoveries than the low permeability samples. This was true for all three types of live oil used.

13. Additives in the live oil did not seem to play an important role in steamflood recovery in both the high and the low permeability samples.

14. Steamflooding recoveries were very low mainly due to the low percentage of oil left in place after pressure drawdown stage.

In the overall comparison, note that in phase 3, steamflooding no additives were used, where in phase 2 steamflooding with additives were used. It seems that additives during steamflood do improve recovery.

5.3 PHASE 4: "LIVE" LLOYDMINSTER CRUDE TEST

The main results are presented in Table 4.32, and the differential recoveries from baseline are presented in Table 5.4.

5.3.1 Heat Up Recovery

As discussed earlier, the average heat-up recovery was calculated by averaging the heat-up recoveries from all runs. The exception to this was carbon dioxide runs which were not included. The reason being that in Experimental Type 1, the bubble point pressure of oil was lower than the bubble point pressure of the oil used in the other runs. The other reason pertaining to the runs in Experimental Type 2, was that the operating pressure was approximately 2 MPa higher than the other runs. Therefore, the carbon dioxide runs in Experimental Type 1 and Type 2 were averaged separately.

There are thus three averages to discuss here as presented in Table 4.32. First is the average of the no additives, nitrogen and methane runs (27.73% OOIP); the second is the average of the runs with carbon dioxide in Experimental Type 1 (38.09% OOIP); and the third is the average of the runs with carbon dioxide in Experimental Type 2 (18.28% OOIP).

The bubble point pressure of the "live" oil for the runs that averaged 27.73% OOIP recovery ranged from 6.8-7.2 Mpa, with an operating pore pressure of 7.5-8.0 Mpa. The bubble point pressure of the "live" oil for the CO_2 runs that averaged 38.09% OOIP was 5.1 Mpa, and the operating pore pressure was 5.5-6.00 Mpa. The bubble point pressure of the "live" oil for the CO_2 runs that averaged 18.28% OOIP was 5.1 Mpa, and the operating pore pressures ranged from 8.0 to 9.5 Mpa.

The thermal expansion test showed a volumetric expansion of 22.60% at 8 Mpa. It is important to take note of the pressure since it is believed that heat up recoveries are influenced by pressures.

It is believed that the reason for the high average recovery (38.09 %OOIP) of the carbon dioxide runs in Experimental Type 1 is that the pore pressure was low (5.5-6.0 Mpa), compared to other runs. This resulted in some outgassing of the oil, thereby leading to higher recoveries. On the other hand, the low average recovery (18.28 %OOIP) for the carbon dioxide runs in Experimental Type 2, is believed to be caused by high pore pressures (8.0-9.5 MPa), keeping the dissolved gas in solution.

The difference in recoveries between the two sets of carbon dioxide runs (38.09% vs 18.28%) suggests that outgassing is an effective mechanism for improving oil recovery during heat up stage (a conclusion also drawn for the artificial "live" Athabasca tests of Phase 3).

The role of outgassing in the thermal expansion test which resulted in 22.60%, is not known. For this reason, no conclusions can be made regarding the role of irreducible water saturation in the heat up stage.

5.3.2 Waterflooding Recovery

5.3.2.1 High Permeability Samples

Both nitrogen and methane led to significant improvements in waterflood recovery, while carbon dioxide led to a significant decrease in waterflood recovery.

The low oil recoveries resulting from the water/carbon-dioxide runs are attributed to two factors (both outcomes of the relatively low bubble point and operating pressures). One, that there was less oil-in-place, and two, that there was a higher degree of outgassing that occured in the heat-up stage.

5.3.2.2 Low Permeability Samples

In the low permeability samples similar results were observed. The highest waterflood recovery resulted from the water/methane runs, and the lowest from the water/carbon-dioxide runs.

A comparison of the recoveries between the three sets of runs which used similar quality live oil (similar bubble point and pore pressures), showed a significant difference between the baseline recovery (water/no-additives) to that of water/nitrogen and water/methane. The difference here suggests that additives in waterflood do improve oil recovery in the low permeability samples.

5.3.2.3 Comparison of Waterflooding Results Between the Two Permeability Types

Waterflooding with no additives was slightly more effective in the high permeability samples than the low permeability samples. However, this difference is not statistically significant. The high permeability run resulted in 19.30 %OOIP, whereas the low permeability run resulted in 16.37 %OOIP.

The recoveries for all the additive runs in the lower permeability smaples were higher than in the higher permeability samples. This suggests that some dissolution of the additives into the oil occurred in the lower permeability samples. This further suggests that perhaps conditions for miscibility were more conducive in the lower permeability samples than in the higher permeability samples, due to capillary pressure retardation of gas flow.

5.3.3 Pressure Drawdown Recovery

5.3.3.1 Experimental Type 1

5.3.3.1.1 High Permeability Samples

In all cases, the additives led to reduced recovery over the baseline case, but in no instance was this reduction statistically significant.

Three possible mechanisms can cause displacement in the pressure drawdown stage: flashing of water (irreducible plus mobile), evolution of solution gas and expansion of gas already in the pore space. In order to indentify the mechanism that plays the major role, it is necessary to compare the results of water/carbon-dioxide run with any of the water/no-additive, water/nitrogen, or water/methane runs. The reason for using this comparison is that in the water/carbon-dioxide run, there was more outgassing from the "live" oil in the heat-up stage (due to the lower bubble point pressure) than the other runs. Therefore less solution gas in the oil but likely more gas present in the pore space for this run. However, the results show that the recoveries for water/carbon-dioxide and any of the other runs, for example, the water/methane run were virtually the same. This suggests that the evolution of solution gas from oil and the presence of free gas did not affect pressure drawdown recovery. Flashing of irreducible plus mobile water, therefore, seems to be the major mchanism.

5.3.3.1.2 Low permeability samples

The pressure drawdown recoveries for the low permeability samples showed significant recovery decreases relative to the baseline for nitrogen and carbon dioxide, but similar (although somewhat reduced) productions for methane.

The relatively high oil recoveries for the water/methane runs as compared with the recovery in the water/carbon-dioxide run indicates that, in the lower permeability samples, evolution of solution gas did play an important role in improving oil recovery. This is again due to the fact that in the water/carbon-dioxide run, the oil was less satuarted with the solution gas than the live oils in the other runs, as explained earlier.

The low recovery results of pressure drawdown in the water/nitrogen run, may be explained by the fact that when nitrogen was injected with water, it created gas channels . Since nitrogen has very low solubility with oil, when the pressure was lowered and the solution gas evolved, it followed channels created by the nitrogen gas. This reduced the efficiency of the pressure drawdown stage.

5.3.3.1.3 Comparison of the pressure drawdown recoveries between the two permeability types in Experimental Type 1

The main difference between the two permeability types was the mechanism involved in oil recovery. In the high permeability samples, flashing of water seemed to be the major mechanism of recovery, with a minor role by the evolution of gas from oil. Whereas, in the low permeability samples, evolution of the solution gas seemed to have a more significant effect on oil recovery.

Since the cumulative recoveries, after heat-up and waterflood stages, in the water/nitrogen runs, and between the two types of permeabilities were approximately the same, it is appropriate to compare the results of the pressure drawdown stage.

In the high permeability runs, the average pressure drawdown recovery was 14.92 %OOIP, whereas in the low permeability runs it was 6.63 %OOIP. This suggests that the mechanism in the high permeability samples was more effective than the mechanism in the low permeability samples. This mechanism was flashing of water with very little contribution from gas evolution.

A comparison between the results of the water/carbon-dioxide run for the two types of permeabilities confirms the above findings.

5.3.3.2 Experimental Type 2

5.3.3.2.1 High Permeability Samples

The recovery in the heat-up process for the carbon-dioxide run was much lower than in the other runs due to a lesser degree of "live" oil outgassing as the result of the higher pressure held on the oil during heat-up process. It is speculated that for this reason, the pressure drawdown recovery for the carbon-dioxide run was higher than the other runs, both because of a larger amount of oil in place, and the higher bubble point pressure.

The high oil recovery in the pressure drawdown process for the carbon-dioxide run also suggested that a larger volume of gas in solution improved oil recovery.

5.3.3.2.2 Low Permeability Samples

The average pressure drawdown recoveries in Table 5.5 were very similar, although in the case of the carbon-dioxide run there was more oil-in-place after heat-up. This means that the larger volume of solution gas in the live oil (in the carbon dioxide run) which was caused by maintaining a higher pore pressure on the oil, did not improve recovery. In this comparison, the percentage of oil left in place after heat up was taken into consideration. The results suggest that the evolution of gas from live oil did not play an important role in the recovery mechanism (the recovery mechanism being the flashing of irreducible water).

5.3.3.2.3 Comparison of Pressure Drawdown Recoveries Between the Two Permeability Types in Experimental Type 2

Pressure drawdown seemed to be affected by the evolution of solution gas in the high permeability samples, but not significantly affected in the low permeability samples.

5.3.3.3 Comparison of Pressure Drawdown Results Between Experimental Type 1 and 2

It was discussed that in Experimental Type 1 that the effect of gas evolution was different in each permeability type. In the high permeability samples, gas evolution seemed to have a minor effect in oil recovery whereas in the low permeability samples it had no effect.

In Experimental Type 2, however, evolution of solution gas seemed to be effective in the high permeability samples, but not very effective in the low permeability samples.

In the high permeability samples of Experimental Type 1, waterflooding with or without additives apparently created water and/or gaseous channells. When pressure was drawn down, the evolved gas broke through the existing channels, resulting in less efficient process. In Experimental Type 2 (in the high permeability samples) where no waterflooding was performed, evolution of solution gas became more effective in recovery since there were no existing channels along which the gas could escape. The evolved gas, therefore, displaced oil as it was exiting the sample.

It should be mentioned that when the pressure is drawn down from the original pore pressure (7-8 Mpa) down to 2 Mpa, the live oil will evolve solution gas long before the water flash point is reached. At a temperature of 250 C, water flashes at approximately 4 Mpa. For most of the oils, the bubble point pressure was around 7 Mpa. Therefore, once the pressure is below 7 Mpa, the "live" oil will evolve solution gas. The gas will then channel through as it is being evolved from the oil. Once the flash point of water is reached, the violent process of flashing recovers further oil. The flashing process might also lead to disruption of existing flow channels, thereby allowing more efficient production of the displaced oil. This could suggest that flashing of water became the dominant mechanism in recovering oil during the pressure drawdown stage.

5.3.4 Steamflooding Recovery

5.3.4.1 Experimental Type 1

5.3.4.1.1 High Permeability Samples

The additives showed no significant effect in oil recovery by steamflooding.

5.3.4.1.2 Low Permeability Samples

Both nitrogen and carbon dioxide showed no significant difference from the baseline recovery.

The steam/methane run did show a significant difference. This is improtant because there was significantly less oil-in-place at the time of steamflood as compared to the other runs. These results suggest that the stripping mechanism in the case of the steam/methane run was augmented by the dissolution of methane into the oil, causing swelling and reduction in viscosity, although this cannot be substantiated.

5.3.4.1.3 Comparison of Steamflood Recoveries Between the Two Permeability Types in Experimental Type 1

Very little scatter was found between the recoveries of the two types of permeabilities in the steam/no-additive, steam/nitrogen and steam/carbon-dioxide runs. The only difference was that in the case of the low permeability samples, there was slightly more oil-in-place before steamflooding than in the higher permeability samples. The steam/methane runs which resulted in the highest recoveries in both types of permeability, showed that in steamflooding (Experimental Type 1), dissolution of gaseous additives may lead to improved oil recovery.

5.3.4.2 Experimental Type 2

5.3.4.2.1 High Permeability Samples

Additives in this case did not seem to improve oil recovery. The stripping mechanism was not, therefore, affected by the additives.

5.3.4.2.2 Low Permeability Samples

For all additives, a significant increase in recovery was observed. Since nitrogen has very low solubility with oil, dissolution was overruled. In the case of steam/carbon-dioxide and steam/methane, dissolution may have been involved with stripping. However, in view of the results from the steam/nitrogen run, no conclusion can be drawn regarding any other mechanism in addition to stripping.

5.3.4.2.3 Comparison of Steamflood Recoveries Between the Two Permeability Types in Experimental type

In the high permeability samples, additives did not seem to be effective in improving oil recovery. In the low permeability samples, however, additives did improve oil recovery.

5.3.4.3 Comparison of Steamflood Recoveries Between Experimental Type 1 and 2

The results of the steamflood recoveries for the high permeability samples in both Experimental Type 1 and 2 were very similar, indicating very little difference in the mechanism involved in the two experimental types. The percentage of the oil-in-place prior to steamflooding for all runs in both experimental types were very simliar, allowing this comparison to be made.

In both experimental types, the steam/methane run resulted in slightly higher recovery than the other runs. Considering the high solubility of methane in oil, the results here suggest that dissolution of gaseous additives can improve recovery. Therefore the dominant mechanism here seems to be mechanical stripping of oil. However, in the low permeability runs, the results seemed to indicate that addition of additives in steamflood did improve oil recoveries. In Experimental Type 1, the highest recovery resulted from steam/methane and in Experimental Type 2, the steam/carbon-dioxide and steam/methane runs were the highest. Therefore, dissolution of the gaseous additives with high solubility tendencies seem to play a role in improving oil recovery, at least in low permeability samples.

5.3.5 Summary of the Conclusions for Phase 4

1. The heat-up recovery varied with bubble point and operating pore pressures of the live oil. The heat-up recovery resulting from "live" oil with bubble point pressure of 6.8-7.2 Mpa and operating pore pressure of 7.5-8.0 Mpa was 27.73% OOIP; from the live oil with approximately the same bubble point pressure but higher operating pore pressure of 8.0-9.5 Mpa was only 18.28% OOIP; and from the live oil with a bubble point pressure of approximately 5 Mpa and operating pore pressure of 5.5-6.0 Mpa was 38.09% OOIP.

3. The results indicated that out-gassing (evolution of solution gas) from the live oil during heat-up process was very effective in improving oil recovery. This was based on the result that higher operating pore pressure recovered less oil than lower pressure, and that generally higher pressure tends to supress out-gassing.

4. Thermal expansion test performed on the "live" oil with a bubble point pressure of approximately 7 Mpa and operating pore pressure of 8 Mpa, resulted in 22.60% volumetric thermal expansion. This was from a temperature of 80 C to 250 C.

5. No significant difference in waterflooding recovery in the high permeability samples was found between the base-line water/no-additive and water/with-additive recoveries. This suggested that in the high permeability samples additives did not improve recovery.

6. The low waterflooding recovery of water/carbon-dioxide run which used the 'live' oil with the low bubble point and operating pore pressure, and which resulted in higher degree of out-gassing of oil in the heat-up process, indicated that the more dissolved gas in oil, the more efficient the waterflooding will be. The main mechanism involved with dissolved gas in oil lowering the viscosity and hence making the oil more mobile.

7. A comparison between the waterflooding results of the base-line water/no-additive and water/with-additives in the low permeability samples, indicated that additives did improve waterflooding recovery.

8. The low oil recovery of the water/carbon-dioxide waterflooding recovery, suggested that dissolution of gas into oil improves oil recovery.

9. From 8 and 9 above, it is concluded that gaseous additives injected along with water were dissolved in oil.

10. In experimental type 1 (high permeability samples) the main

mechanism in the pressure drawdown process seemed to be flashing of water saturation.

11. In experimental type 1 (low permeability samples) evolution of gas from oil seemed to play an important role in pressure drawdown recovery.

12. Injection of nitrogen along with water in waterflooding in the low permeability samples, seemed to have an adverse effect on oil recovery. It was speculated that nitrogen created gas channeles during waterflooding process which caused the evolved gas in the pressure drawdown process to follow, resulting in an inefficient process.

13. The pressure drawdown recoveries in experimental type 2 indicated that in the high permeability samples, evolution of gas from live oil did improve recovery, whereas in the low permeability samples, it did not.

14. A comparison of the pressure drawdown recoveries in the experimental type 2, between the low and the high permeability samples indicated that evolution of gas from live oil during pressure drawdown significantly improves recovery.

15. The cumulative oil recovery in experimental type 1 and type 2 after pressure drawdown process were compared. The results indicated no significant difference between the two. Waterflooding, in general therefore, did not improve ultimate recovery.

16. Very little scatter was found between the steamflooding results in experimental type 1 of the low and the high permeability samples. In both permeability types, steam/methane runs resulted in the highest recoveries.

17. Dissolution of methane injected with steam in steamflooding process seem to improve recovery.

18. Additives in steamflooding process in experimental type 2 in the high permeability samples did not seem to improve oil recovery. In the low permeaiblity samples, however, additives did indicate to improve recovery.

19. In general, additives injected with steam in steamflooding process improve oil recovery.

5.4 DISCUSSION OF MECHANISMS

5.4.1 Introduction

The results of all phases were compared and the contributions from the various mechanisms to the overall recovery was determined. These mechanisms are discussed here.

5.4.2 Thermal Expansion

The initial water and oil in place expand when heated. The rate of expansion for each fluid is different. For example, as shown below, an oil which contains solution gas, has a higher thermal expansion rate than an oil which does not.

3% solution of NaCl:	12.67% from 80 C to 250 C.
Distilled water:	17.80% from 80 C to 250 C.
"Dead" Athabasca bitumen:	12.67% from 80 C to 250 C.
Athabasca bitumen saturated with nitrogen:	22.0% from 80 C to 250 C.
Athabasca bitumen saturated with carbon dioxide:	26.2% from 80 C to 211 C.
Athabasca bitumen saturated with methane:	38.6% from 80 C to 216 C.
"live" Lloydminster:	22.6% from 80 C to 250 C.

The above experimentally determined thermal expansion rates provide the lower and the upper limits of oil recovery in the heat-up recovery stage. The upper and the lower limits are defined by how each fluid contributes to oil production. If the expanded water gets produced in its entirety, then the lower limit of production is the thermal expansion of the bitumen. If, on the other hand, the water does not get produced, but rather provides a drive for oil to be produced, then the upper limit is the thermal expansion of oil and water.

In Phases 3 and 4, where gas was dissolved in the bitumen (artificially saturated Athabasca and live Lloydminster), heat-up also caused gas evolution. The results showed that thermal expansion leads to an average oil production of approximately 14.2% OOIP. If the expanding water is produced direcly, it may be calculated that 12.7% OOIP should be the thermal expansion production. If the expanding water leads to oil production, the mean thermal expansion production may be calculated to be 17.0% OOIP. The experimental results therefore indicate that some of the expanding water is produced directly, while some of the expanding water displaces oil.

5.4.3 Connate water flashing

The role of connate water flashing may be determined by examining the results of Phase 2, Experimental Type 2. Here, the average recoveries were permeability dependent, with 33.0 %OOIP recovered for the high permeability samples, and 37.6 %OOIP recovered for the low permeability samples. Connate water flashing is, therefore, a major mechanism for the recovery of Athabasca bitumen.

The results also show that for the high permeability samples, connate water flashing in a pressure drawdown stage was responsible for a recovery of approximately 61% of the ultimate recovery and for the low permeability approximately 58%.

5.4.4 Oil "liveness"

Two processes of heat-up and pressure drawdown are considered here. If a "live" oil (one containing solution gas) is heated, the dissolved gas may come out of solution. This evolving gas provides a drive mechanism to displace oil. As for the thermally expanding gas, however, this gas may channel to the production end, bypassing the oil, and not cause additional production. The role of oil liveness may be examined by comparing the results for the thermal expansion stages of all three phases.

For Phase 3, where artificially saturated Athabasca oil was used, all runs led to improved recovery. The improved recovery was higher for high permeability samples in the case of nitrogen and methane. The significance of these permeability dependent trends is not clear due to the small data population. The average recoveries for the high and low permeability samples, that is attributed to outgassing is as follows:

carbon dioxide:	28.0 %OOIP
methane:	13.5 %OOIP
nitrogen:	10.0 %OOIP

The contributions of thermal expansion and oil liveness for Phase 4 cannot be determined for the heat-up process, since tests with the "dead" Lloydminster crude were not performed.

However, if the heat-up recoveries for the Experimental Type 2, carbon dioxide runs (18.3 %OOIP) are assumed to represent a low degree of out-gassing, then they can be used as an upper limit of the contribution of thermal expansion. The oil liveness contribution can then be estimated as 9.5 %OOIP (based on the average of all runs except those using carbon dioxide). In the case of Experimental Type 1, and carbon dioxide, where a significantly greater amount of outgassing was anticipated due to the low initial bubble point pressure (and pore pressure), the outgassing contirbution was 19.8 %OOIP. Both above estimates are minimums because of the estimated nature of the thermal expansion contribution.

For all the cases (artificially saturated Athabasca and live Lloydminster), where a significant degree of outgassing was expected, the oil production, relative to the evolved gas volume, was small. This implies that significant gas channelling occurred.

For the pressure drawdown stage in Phase 3, the results were expressed as %OOIP. However, these results must be interpreted in light of the fact that there was much less oil in place at the beginning of the pressure drawdown stage. If the results are reinterpreted based on percent oil in place at the beginnning of the pressure drawdown stage, and if the high and low permeability results are averaged, then the following values are obtained:

nitrogen saturated Athabascaca	41.3 %OIP
carbon dioxide saturated Athabasca	72.1 %OIP
methane saturated Athabasca	68.3 %OIP

The equivalent value for the case of "dead" Athabasca crude is 41.1 %OOIP. Since this production is due to connate water flashing only, it is clear by comparing these numbers that the liveness due to carbon dioxide and methane lead to significant improvements in recovery. The result for the nitrogen saturated oil is identical to that for the "dead" oil.

This suggests that all of the nitrogen came out of solution during the heat-up process, and that all of the production for the nitrogen saturated bitumen was due to connate water flashing.

Phase 4 (pressure drawdown stage) results for Lloydminster do not separate connate water flashing and outgassing effects. However, the carbon dioxide results provide a means for an approximate analysis. For Experimental Type 2, the following productions as %OOIP may be calculated:

High permeability

All runs except carbon dioxide	50.3 %OIP
Carbon dioxide runs	59.3 %OIP

Low permeability

All runs except carbon dioxide	39.5 %OIP
Carbon dioxide runs	37.1 %OIP

These results imply that, the presence of more solution gas (the carbon dioxide runs) leads to improved recovery in the high permeability samples, but not in the low permeability samples. These results must be used with caution due to the limited data set.

5.4.5 Dissolution/Evolution of gases

The effects of gas dissolution/evolution may be interpreted by comparing the results of Phases 2 and 3 (Experimental Type 2). It was shown above that in both cases, dissolved additives lead to significant improvements in production, with carbon dioxide outperforming the other two. However, these results must be interpreted with caution. The additives in these experiments wer recombined with the oil. It is highly unlikely that a field process could be developed in which the same degree of additive dissolution could be achieved, particularly before the reservoir was heated.

5.4.6 Mechanical stripping

Both water and steam, as thy pass through the pore space, produce oil by means of viscous drag. In this process, the moving phase exerts viscous forces on immobile oil which is held in place by capillary forces. If the viscous force is greater than the capillary force, then the oil is entrained and eventually produced. This process will be termed "mechanical stripping". Its importance may be examined by considering the no additive runs in Phases 2 and 4.

For the waterflood case, both the Athabasca and Lloydminster results indicat that recovery decreases slightly as permeability decreases. When expressed in terms of %OIP before waterflood, the following results are obtained:

Permeability	Phase 2	Phase 4
High	36.8 %OIP	26.7 %OIP
Low	34.1 %OIP	22.7 %OIP

Recovery for the Lloydminster crude is lower than that for Athabasca bitumen. This may be due to the presence of prefered flow channels caused by outgassing of the Lloydminster oil during the heat-up process.

For the steamflood, the results are more difficult to analyse since other stages had proceeded this one. For Phase 4, the steamflood without additives results are remarkably similar regardless of experimental type, yielding values in the range of 5.67 %OOIP to 7.48 %OOIP. For the Athabasca results, the low permeability samples yield essentially indentical results (13.50%) regardless of experimental type. The high permeability results (6.85 %OOIP to 10.43 %OOIP) do not agree as well but are both lower than for the low permeability tests.

5.4.7 Chemical stripping

The addition of additives to a flood fluid, if it dissolves in the oil, can cause swelling and viscosity reduction, both of which should aid in production. This process will be termed "chemical stripping". By examining the differenes between baseline and additives runs, these effects can be quantified.

During waterflood of the "dead" Athabasca bitumen, only carbon dioxide lead to a significant increase in recovery (6.3 %OOIP) in the high permeability samples. In the low permeability samples, all additives lead to significant improvements (up to 24 %OOIP for methane).

During waterflooding in the "live" Lloydminster runs, discounting the carbon dioxide results because of the differences in operating conditions, both nitrogen and methane lead to significant increases in production in both low and high permeability samples. Consistent with the Athabasca results, the recovery improvement for methane was higher than for nitrogen, while both additives had improved performance in the low permeability samples (approximately double). Overall, improvements on the order of 5-10 %OOIP may be expected by adding methane or carbon dioxide to water when flooding.

As discussed before, steamflood results are more difficult to interpret because of the other stages which proceeded it. For Phase 4, there is an evidence of any chemical stripping except for the case of Experimental Type 2, low permeability samples. For Phase 2, there is much more scatter, with only isolated tests showing improved recovery. These results imply that the addition on non-condensible gases to steam does not lead to improved recovery.

6. MAIN CONCLUSIONS

The reader is reminded that the following conclusions are based on isothermal, one dimensional linear coreflood tests. Additional mechanisms, and increased effectiveness of the suggested mechanisms, may be operational if two dimensional, non-isothermal conditions occur.

The work described herein supports the following conclusions:

1. Heating of the following oils is responsible for the following recoveries:

"Dead" Athabasca	14.2 %OOIP
"Live" Lloydminster	27.7 %OOIP

Of these, all of the Athabasca recovery can be attributed to thermal expansion, while for the Lloydminster recovery, more than 9.5 %OOIP can be attributed to outgassing.

2. Additives dissolved in Athabasca bitumen are very effective in improving recovery during heat up process. Nitrogen increased recovery by 10% OOIP, methane by 13% OOIP and carbon dioxide by 28% OOIP.

3. Waterflood recoveries for the Athabasca bitumen were approximately 35 %OIP, while the "live" Lloydminster tests yielded recoveries of approximately 25 %OIP. The "live" Lloydminster results are influenced by the presence of gas channels caused by outgassing during heat-up.

4. The addition of additives during waterflooding resulted in increased recovery, particularly in the case of low permeability samples. The most significant additives were carbon dioxide and methane, although nitrogen did provide some improvement in recovery.
5. Pressure drawdown, which led to a flashing of the connate water and outgassing (if the oil is "live"), resulted in a significant oil reocvery, regardless of whether the sample had been waterflooded or not. After waterflood, these recoveries were on the order of 20% OOIP, while in the absence of waterflood, the recoveries were on the order of 35% OOIP.

6. Additives (added with waterflood) were generally ineffective during the flashing (pressure drawdown) process.

7. A twin process of waterflooding (with or without additives) followed by pressure drawdown was a much more effective recovery process than a single process of pressure drawdown (huff-and-puff). The Athabasca showed that an additional 20% OOIP results when the twin process is used.

8. Carbon dioxide and methane dissolved in Athabasca bitumen ("live"), caused a significant improvement in pressure drawdown recovery. Nitrogen on the other hand appears to be disadvantageous in this process. This is attributed to gas channelling initiated during heat up stage. The result here only applies for a pressure drawdown stage without a prior waterflooding. Whether these results apply to a case without waterflooding is not known, since the "live" Athabasca tests did not include waterflooding.

9. Steamflooding (without additive) provided a 6% OOIP for Lloydminster, but somewhat better production for Athabasca (7 to 14 %OOIP), particularly in low the permeability samples.

10. Additives were generally ineffective in improving steamflooding recovery.

7. RECOMMENDATIONS

1. Two-dimensional mechanistic experiments using tar sand samples should be conducted to verify and to complement the present study.

2. Experiments with "dead" Lloydminster crude (one and two dimensional) should be included in any future study, to allow direct comparison beween connate water flashing versus out-gassing during the various processes.

3. Experiments should be performed in non-isothermal conditions (one or two dimensional), where steam is injected prior to pressure drawdown, to allow the examination of the role of additives and pressure gradient maintanance in recovery.

4. Waterflooding in artificially saturated Athabasca bitumen should be performed to study the effect of out-gassing after heat-up stage by comparing with the "dead" Athabasca bitumen waterflooding.

Table 2.1

Petrophysical properties for the samples used in Phase 2

Run #	Sample Type	Porosity (%)	Gas Permeability (md)	Grain Density (kg/m3)	Diameter (cm)	Length (cm)
1	Brown SS	23.8	3724.44	2631	3.98	20.29
2	Brown SS	23.2	3760.91	2645	3.93	20.24
3	Berea SS	17.6	96.28	2648	3.94	20.17
4	Berea SS	17.4	94.34	2673	3.85	20.10
5	Brown SS	21.9	3369.17	2614	3.94	20.39
6	Brown SS	21.6	1854.43	2633	3.94	20.45
7	Berea SS	17.2	127.27	2652	3.92	20.18
8	Berea SS	18.0	133.00	2653	3.90	20.05
9	Brown SS	21.1	1014.44	2624	3.91	20.12
10	Brown SS	20.9	1016.61	2626	3.91	20.27
11	Berea SS	19.0	116.93	2682	3.90	20.08
12	Berea SS	18.3	116.67	2672	3.90	20.19
13	Brown SS	21.3	1097.01	2645	3.92	20.01
14	Brown SS	22.9	1059.11	2643	3.93	20.23
15	Berea SS	18.8	116.66	2673	3.92	20.14
16	Berea SS	18.0	116.17	2680	3.90	20.37
17	Brown SS	22.7	2765.87	2657	3.92	20.08
18	Brown SS	22.7	2689.28	2640	3.87	19.79
19	Berea SS	18.4	120.23	2676	3.91	20.27
20	Berea SS	18.4	125.09	2681	3.92	20.20
21	Brown SS	22.7	3074.71	2620	3.86	20.06
22	Brown SS	21.1	2983.91	2641	3.85	19.85
23	Berea SS	18.7	131.05	2677	3.92	20.18
24	Berea SS	17.8	133.02	2670	3.87	20.28
25	Brown SS	21.8	1227.81	2661	3.91	20.18
26	Brown SS	22.3	635.92	2648	3.93	20.20
27	Brown SS	21.0	3598.58	2647	3.92	19.78
28	Berea SS	17.7	100.72	2630	3.92	19.93
29	Berea SS	18.0	96.42	2644	3.89	19.89
30	Brown SS	20.1	616.60	2628	3.90	19.90
31	Brown SS	22.2	719.30	2668	3.91	20.31
32	Berea SS	18.2	94.34	2673	3.85	19.93
33	Berea SS	18.0	95.92	2653	3.90	19.50

Table 2.2

Petrophysical Properties for the samples used in Phase 3

Run #	Sample Type	Porosity (%)	Gas Permeability (md)	Grain Density (kg/m^3)	Diameter (cm)	Length (cm)
1	Brown SS	21.2	983.71	2623	3.92	20.22
2	Brown SS	20.9	1004.85	2643	3.87	19.68
3	Berea SS	17.5	112.02	2669	3.90	20.14
4	Berea SS	17.9	114.04	2686	3.90	20.14
5	Brown SS	20.2	797.52	2647	3.88	20.16
6	Brown SS	20.9	804.68	2636	3.90	19.98
7	Berea SS	17.6	109.29	2663	3.90	20.14
8	Berea SS	18.7	109.61	2676	3.92	20.10
9	Brown SS	22.0	800.87	2643	3.92	20.22
10	Brown SS	21.6	834.66	2639	3.92	19.86
11	Berea SS	17.6	108.34	2661	3.88	19.91
12	Berea SS	18.3	111.48	2673	3.92	20.27

Table 2.3

Petrophysical properties for the samples used in Phase 4

Run #	Sample Type	Porosity (%)	Gas Permeability (md)	Grain Density (kg/m^3)	Diameter (cm)	Length (cm)
1	Brown SS	19.9	691.88	2626	3.91	20.24
2	Brown SS	18.8	633.31	2626	3.90	20.45
3	Berea SS	20.3	83.06	2724	3.93	19.94
4	Berea SS	18.4	83.89	2698	3.90	19.91
5	Brown SS	20.6	832.27	2678	3.86	19.77
6	Brown SS	22.4	948.82	2685	3.87	20.00
7	Berea SS	19.1	74.49	2718	3.90	19.95
8	Berea SS	17.2	74.74	2705	3.88	19.93
9	Brown SS	22.4	1628.13	2659	3.92	20.07
10	Brown SS	21.7	1648.47	2680	3.86	19.88
11	Berea SS	17.8	83.41	2679	3.84	20.29
12	Berea SS	17.0	82.14	2702	3.87	19.92
13	Brown SS	22.8	1237.67	2656	3.90	20.18
14	Brown SS	20.4	1595.06	2687	3.86	19.82
15	Berea SS	17.2	78.79	2676	3.84	20.09
16	Berea SS	18.3	76.26	2722	3.89	19.25
17	Brown SS	21.4	2340.60	2669	3.89	19.33
18	Brown SS	22.3	1750.03	2643	3.96	20.30
19	Berea SS	18.9	144.94	2675	3.91	20.17
20	Berea SS	17.5	102.33	2685	3.89	18.92
21	Brown SS	22.2	3533.65	2680	3.86	19.92
22	Brown SS	22.1	3548.40	2681	3.86	20.15
23	Berea SS	20.3	98.12	2755	3.86	20.05
24	Berea SS	17.9	119.25	2704	3.90	19.82
25	Brown SS	22.3	879.53	2672	3.90	20.06
26	Brown SS	21.2	709.71	2668	3.89	19.82
27	Berea SS	18.5	97.29	2686	3.88	18.89
28	Berea SS	18.2	97.24	2684	3.90	18.95
29	Brown SS	20.5	639.68	2666	3.87	19.65
30	Brown SS	20.3	628.14	2675	3.89	19.43
31	Berea SS	18.8	97.73	2680	3.88	19.23
32	Berea SS	18.3	97.47	2691	3.87	18.70

Table 4.1

Mean S_{wi} for each Permeability group in Phase 2

Permeability group	No of samples used in the average	Mean S_{wi} (%)
Low	13	19.00
Medium	5	18.41
High	7	17.45

Low permeability: Berea Sandstone
Medium permeability: Brown Sandstone
High permeability: Brown sandstone

Table 4.2

Results of the oilflooding stage in Phase 2

RUN #	PORE VOLUME (cc)	POROSITY (%)	Kgas (mD)	MASS OF WATER IN SAMPLE @ 100% SAT (g)	VOLUME OF WATER PRODUCED BY OILFLOOD (cc)	DENSITY OF WATER @ SG TEMP (g/cc)	MASS OF WATER IN SAMPLE AFTER OILFLOOD (g)	Swi (%)
1	60.07	23.8	3724.44	60.07	46.26	1.014	13.16	21.91
2	56.89	23.2	3760.91	56.89	46.00	1.021	9.93	17.45
3	43.06	17.6	96.28	43.06	34.50	1.011	8.18	19.00
4	44.13	17.4	94.34	44.13	36.19	1.020	7.22	16.35
5	54.45	21.9	3369.17	53.91	47.00	1.000	6.91	12.82
6	53.83	21.6	1854.43	53.83	40.37	1.014	12.89	23.95
7	41.90	17.2	127.27	41.90	31.49	1.017	9.87	23.57
8	43.12	18.0	133.00	43.12	36.01	1.020	6.39	14.82
9	50.97	21.1	1014.44	50.97	40.81	1.019	9.39	18.41
10	50.08	20.9	1016.61	50.08	40.18	1.017	9.22	18.41
11	45.57	19.0	116.93	45.57	35.70	1.020	9.16	20.09
12	44.13	18.3	116.67	44.13	36.40	1.020	7.00	15.87
13	51.45	21.3	1097.01	51.45	41.08	1.022	9.47	18.41
14	56.19	22.9	1059.11	56.19	47.30	1.017	8.09	14.39
15	45.70	18.8	116.66	45.70	35.72	1.020	9.27	20.27
16	43.81	18.0	116.17	43.81	34.79	1.020	8.32	19.00
17	55.02	22.7	2765.87	55.02	47.00	1.020	7.08	12.87
18	52.83	22.7	2689.28	52.83	41.34	1.020	10.66	20.18
19	44.78	18.4	120.23	44.78	35.00	1.017	9.19	20.51
20	44.85	18.4	125.09	44.85	35.72	1.017	8.52	19.00
21	53.30	22.7	3074.71	53.30	46.34	1.020	6.03	11.32
22	48.75	21.1	2983.91	48.75	38.05	1.020	9.94	20.39
23	45.55	18.7	131.05	45.55	36.52	1.008	8.74	19.18
24	42.47	17.8	133.02	42.47	34.52	1.020	7.26	17.09
25	52.82	21.8	1227.81	51.34	40.13	1.000	11.21	21.83
26	54.63	22.3	635.92	53.26	41.89	1.000	11.37	21.35
27	50.12	21.0	3598.00	48.87	37.80	1.000	11.07	22.65
28	42.57	17.7	100.72	41.38	34.76	1.000	6.62	16.00
29	42.61	18.0	96.42	41.54	33.17	1.000	8.37	20.15
30	47.85	20.1	616.60	46.65	40.30	1.000	6.35	13.61
31	54.14	22.2	719.30	52.79	41.78	1.000	11.01	20.86
32	42.23	18.2	94.34	41.17	33.43	1.000	7.74	18.80
33	41.97	18.0	95.92	40.92	32.80	1.000	8.12	19.84

Table 4.3

Thermal expansion rates for 3% brine @ 6.89 Mpa - Phase 2

Temperature (C)	Volume in system (cc)	Thermal expansion rates from 80 C (%)
80.5	107.32	0.00
98.5	108.69	1.28
122.0	111.03	3.46
145.5	113.29	5.56
192.0	118.85	11.74
225.0	122.88	14.50
250.0	126.42	17.80

Table 4.4

Thermal expansion rates for the "dead" Athabasca bitumen @ 6.67 Mpa

Temperature (C)	volume in system (cc)	Thermal Expansion rates from 80 C (%)
80.0	295.0	0.00
116.0	301.7	2.26
144.0	307.8	4.33
181.5	314.9	6.76
215.0	323.1	9.54
246.0	332.4	12.67

Table 4.5

Thermal expansion rates for distilled water @ 8 Mpa in Phase 2

Temperature (C)	Thermal expansion rates from 80 C (%)
80	0.00
100	1.35
150	5.86
200	12.07
225	16.21
250	21.27

Table 4.6

Results for the heat-up stage in Phase 2

RUN NUMBER	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS OF RECOVERY DUE TO HEAT-UP (g)	PERCENT RECOVERY DUE TO HEAT UP % OOIP (% mass)
1	60.07	46.15	6.50	14.07
2	56.89	46.20	6.49	14.05
3	43.06	34.32	3.34	9.74
4	44.13	36.32	4.48	12.35
5	54.45	46.24	10.39	22.48
6	53.83	40.27	7.09	17.60
7	41.90	31.51	6.11	19.41
8	43.12	36.14	1.62	4.47
9	50.97	40.91	5.91	14.45
10	50.08	40.20	4.79	11.93
11	45.57	35.83	3.54	9.88
12	44.13	36.53	6.38	17.47
13	51.45	41.30	6.50	15.73
14	56.19	47.33	3.97	8.39
15	45.70	35.85	4.64	12.93
16	43.81	34.91	6.26	17.94
17	55.02	47.17	9.17	19.44
18	52.83	41.49	3.44	8.30
19	44.78	35.02	7.44	21.24
20	44.85	35.74	2.02	5.65
21	53.30	46.50	6.32	13.60
22	48.75	38.18	4.87	12.75
23	45.55	36.22	5.04	13.90
24	42.47	34.64	5.03	14.52
25	52.82	40.17	6.99	17.40
26	54.63	41.93	5.31	12.66
27	50.12	37.84	5.80	17.99
28	42.57	34.80	6.81	16.65
29	42.61	33.20	5.72	17.23
30	47.85	40.34	4.38	10.87
31	54.14	41.82	6.78	16.21
32	42.23	33.46	4.46	13.33
33	41.97	32.83	4.68	14.27

Table 4.7

Results for hot-waterflooding stage in Phase 2

RUN NUMBER	TYPE OF ADDITIVE USED	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS RECOVERY DUE TO WATERFLD (g)	PERCENT RECOVERY DUE TO WATERFLOOD AS %OOIP (% mass)
1	NONE	60.07	46.15	16.82	36.44
2	NONE	56.89	46.20	12.36	26.75
3	NONE	43.06	34.32	10.55	30.74
4	NONE	44.13	36.32	10.07	27.72
9	NITROGEN	50.97	40.91	16.69	40.79
10	NITROGEN	50.08	40.20	10.31	25.64
11	NITROGEN	45.57	35.83	15.61	43.58
12	NITROGEN	44.13	36.53	12.89	35.30
17	CARBON DIOXIDE	55.02	47.17	16.74	35.49
18	CARBON DIOXIDE	52.83	41.49	16.72	40.30
19	CARBON DIOXIDE	44.78	35.02	6.73	19.21
20	CARBON DIOXIDE	44.85	35.74	12.39	34.68
25	METHANE	52.82	40.17	14.52	36.13
26	METHANE	54.63	41.93	12.90	30.76
27	METHANE	50.12	37.84	9.13	24.13
28	METHANE	42.57	34.80	15.82	45.47
29	METHANE	42.61	33.20	20.27	61.04

Table 4.8

Results for the pressure drawdown stage in Phase 2

RUN #	TYPE OF ADDITIVE USED IN WATERFLOOD	EXPRMNT TYPE	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS RECOVERY DUE TO PRESSDDN (g)	PERCENT RECOVERY DUE TO PRESSDDN AS %OOIP (% mass)
1	NONE	1	60.07	46.15	13.59	29.45
2	NONE	1	56.89	46.20	11.89	25.74
3	NONE	1	43.06	34.32	5.76	16.77
4	NONE	1	44.13	36.32	5.11	14.07
5	NONE	2	54.45	46.24	17.73	38.34
6	NONE	2	53.83	40.27	24.40	60.57
7	NONE	2	41.90	31.51	16.94	53.75
8	NONE	2	43.12	36.14	15.30	42.35
9	NITROGEN	1	50.97	40.91	7.71	18.85
10	NITROGEN	1	50.08	40.20	0.00	0.00
11	NITROGEN	1	45.57	35.83	12.32	34.39
12	NITROGEN	1	44.13	36.53	2.35	6.42
13	NITROGEN	2	51.45	41.30	15.76	38.16
14	NITROGEN	2	56.19	47.33	15.62	33.00
15	NITROGEN	2	45.70	35.85	8.54	23.84
16	NITROGEN	2	43.81	34.91	10.25	29.37
17	CARBON DIOXIDE	1	55.02	47.17	5.98	12.68
18	CARBON DIOXIDE	1	52.83	41.49	2.96	7.12
19	CARBON DIOXIDE	1	44.78	35.02	5.09	14.52
20	CARBON DIOXIDE	1	44.85	35.74	7.82	21.89
21	CARBON DIOXIDE	2	53.30	46.50	10.68	22.97
22	CARBON DIOXIDE	2	48.75	38.18	5.52	14.46
23	CARBON DIOXIDE	2	45.55	36.22	0.00	0.00
24	CARBON DIOXIDE	2	42.47	34.64	11.96	34.53
25	METHANE	1	52.82	40.17	9.01	22.42
26	METHANE	1	54.63	41.93	6.49	15.47
27	METHANE	1	50.12	37.84	11.21	29.64
28	METHANE	1	42.57	34.80	2.12	6.08
29	METHANE	1	42.61	33.20	3.35	10.09
30	METHANE	2	47.85	40.34	16.50	40.89
31	METHANE	2	54.14	41.82	15.87	37.94
32	METHANE	2	42.23	33.46	13.37	39.96
33	METHANE	2	41.97	32.83	13.96	42.51

Table 4.9

Results for the steamflooding stage for Phase 2

RUN #	TYPE OF ADDITIVE USED IN STEAMFLOOD	EXPRMN TYPE	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS RECOVERY DUE TO STEAMFLD (g)	PERCENT RECOVERY DUE TO STEAMFLOOD AS %OOIP (%mass)
1	NONE	1	60.07	46.15	5.02	10.88
2	NONE	1	56.89	46.20	4.61	9.98
3	NONE	1	43.06	34.32	6.23	18.17
4	NONE	1	44.13	36.32	3.23	8.90
5	NONE	2	54.45	46.24	0.91	1.96
6	NONE	2	53.83	40.27	4.73	11.74
7	NONE	2	41.90	31.51	2.30	7.30
8	NONE	2	43.12	36.14	7.11	19.68
9	NITROGEN	1	50.97	40.91	6.96	17.02
10	NITROGEN	1	50.08	40.20	0.00	0.00
11	NITROGEN	1	45.57	35.83	2.30	6.41
12	NITROGEN	1	44.13	36.53	1.16	3.18
13	NITROGEN	2	51.45	41.30	5.57	13.49
14	NITROGEN	2	56.19	47.33	3.01	6.37
15	NITROGEN	2	45.70	35.85	8.79	24.53
16	NITROGEN	2	43.81	34.91	3.24	9.28
17	CARBON DIOX	1	55.02	47.17	7.34	15.56
18	CARBON DIOX	1	52.83	41.49	5.94	14.31
19	CARBON DIOX	1	44.78	35.02	2.29	6.54
20	CARBON DIOX	1	44.85	35.74	3.90	10.90
21	CARBON DIOX	2	53.30	46.50	3.51	7.54
22	CARBON DIOX	2	48.75	38.18	6.11	15.99
23	CARBON DIOX	2	45.55	36.22	2.75	7.60
24	CARBON DIOX	2	42.47	34.64	7.90	22.82
25	METHANE	1	52.82	40.17	2.68	6.68
26	METHANE	1	54.63	41.93	3.63	8.66
27	METHANE	1	50.12	37.84	3.21	8.48
28	METHANE	1	42.57	34.80	2.29	6.58
29	METHANE	1	42.61	33.20	1.81	5.47
30	METHANE	2	47.85	40.34	2.95	7.32
31	METHANE	2	54.14	41.82	5.05	12.07
32	METHANE	2	42.23	33.46	5.72	17.10
33	METHANE	2	41.97	32.83	4.58	13.96

Table 4.10

Summary of recoveries for all stages in Phase 2

RUN #	TYPE OF ADDITIVE USED	PERCENT RECOVERY DUE TO HEAT UP %OOIP (%mass)	PERCENT RECOVERY DUE TO WATERFLOOD AS %OOIP (%mass)	PERCENT RECOVERY DUE TO PRESSDDN AS %OOIP (%mass)	PERCENT RECOVERY DUE TO STEAMFLOOD AS %OOIP (%mass)	PERCENT TOTAL RECOVERY AS %OOIP (%mass)
1	NONE	14.07	36.44	29.45	10.88	90.84
2	NONE	14.05	26.75	25.74	9.98	76.52
3	NONE	9.74	30.74	16.77	18.17	75.42
4	NONE	12.35	27.72	14.07	8.90	63.04
5	NONE	22.48	N/A	38.34	1.96	62.78
6	NONE	17.60	N/A	60.57	11.74	89.91
7	NONE	19.41	N/A	53.75	7.30	80.46
8	NONE	4.47	N/A	42.35	19.68	66.50
9	NITROGEN	14.45	40.79	18.85	17.02	91.11
10	NITROGEN	11.93	25.64	0.00	0.00	37.57
11	NITROGEN	9.88	43.58	34.39	6.41	94.26
12	NITROGEN	17.47	35.30	6.42	3.18	62.37
13	NITROGEN	15.73	N/A	38.16	13.49	68.17
14	NITROGEN	8.39	N/A	33.00	6.37	47.76
15	NITROGEN	12.93	N/A	23.84	24.53	61.30
16	NITROGEN	17.94	N/A	29.37	9.28	56.59
17	CARBON DIOX	19.44	35.49	12.68	15.56	83.17
18	CARBON DIOX	8.30	40.30	7.12	14.31	70.03
19	CARBON DIOX	21.24	19.21	14.52	6.54	61.51
20	CARBON DIOX	5.65	34.68	21.89	10.90	73.12
21	CARBON DIOX	13.60	N/A	22.97	7.54	44.11
22	CARBON DIOX	12.75	N/A	14.46	15.99	43.20
23	CARBON DIOX	13.90	N/A	0.00	7.60	21.50
24	CARBON DIOX	14.52	N/A	34.53	22.82	71.87
25	METHANE	17.40	36.13	22.42	6.68	82.63
26	METHANE	12.66	30.76	15.47	8.66	67.55
27	METHANE	17.99	24.13	29.64	8.48	80.24
28	METHANE	16.65	45.47	6.08	6.58	74.78
29	METHANE	17.23	61.04	10.09	5.47	93.83
30	METHANE	10.87	N/A	40.89	7.32	59.08
31	METHANE	16.21	N/A	37.94	12.07	66.22
32	METHANE	13.33	N/A	39.96	17.10	70.40
33	METHANE	14.27	N/A	42.51	13.96	70.74

N/A not applicable. Waterflooding was performed without additives

Table 4.11

Results of the average recoveries for the pair of runs in Phase 2

	EXPERIMENTAL TYPE 1 HIGH PERMEABILITY SAMPLES				
ADDITIVE	AVERAGE HEAT UP RECOVERY AS %OOIP	AVERAGE WATERFLD RECOVERY AS %OOIP	AVERAGE PRSSDDN RECOVERY AS %OOIP	AVERAGE STEAMFLD RECOVERY AS %OOIP	AVERAGE TOTAL RECOVERY AS %OOIP
NONE	14.06	31.60	27.60	10.43	83.69
NITROGEN	13.19	33.22	18.85 *	17.02 *	82.28
CARBON DIOXIDE	13.87	37.90	12.68 *	14.94	79.39
METHANE	16.02	30.34	22.51	7.94	76.81
	EXPERIMENTAL TYPE 1 LOW PERMEABILITY SAMPLES				
NONE	11.05	29.23	15.42	13.54	69.24
NITROGEN	13.68	39.44	20.41	4.80	78.33
CARBON DIOXIDE	13.45	34.68 *	21.89 *	8.72	78.74
METHANE	16.94	53.26	8.09	6.03	84.32
	EXPERIMENTAL TYPE 2 HIGH PERMEABILITY SAMPLES				
NONE	20.04	N/A	38.34 *	6.85	65.23
NITROGEN	12.06	N/A	35.58	9.93	57.57
CARBON DIOXIDE	13.18	N/A	18.72	12.12	44.02
METHANE	13.54	N/A	39.42	9.71	62.67
	EXPERIMENTAL TYPE 2 LOW PERMEABILITY SAMPLES				
NONE	11.94	N/A	48.05	13.49	73.48
NITROGEN	15.44	N/A	26.61	16.91	58.96
CARBON DIOXIDE	14.21	N/A	34.53 *	15.21	63.95
METHANE	13.00	N/A	41.24	15.53	69.77

* based on the result of a single run

Table 4.12

Final results for Phase 2

ADDITIVE	AVERAGE HEAT UP RECOVERY AS %OOIP	AVERAGE WATERFLD RECOVERY AS %OOIP	AVERAGE PRSSDDN RECOVERY AS %OOIP	AVERAGE STEAMFLD RECOVERY AS %OOIP	AVERAGE TOTAL RECOVERY AS %OOIP
EXPERIMENTAL TYPE 1 HIGH PERMEABILITY SAMPLES					
NONE	14.16	31.60	27.60	10.43	83.79
NITROGEN	14.16	33.22	18.85*	17.02	83.25
CARBON DIOXIDE	14.16	37.90	12.68	14.94	79.68
METHANE	14.16	30.34	22.51	7.94	74.95
EXPERIMENTAL TYPE 1 LOW PERMEABILITY SAMPLES					
NONE	14.16	29.23	15.42	13.54	72.35
NITROGEN	14.16	39.44	20.41	4.80	78.81
CARBON DIOXIDE	14.16	34.68	21.89*	8.72	79.45
METHANE	14.16	53.26	8.09	6.03	81.54
EXPERIMENTAL TYPE 2 HIGH PERMEABILITY SAMPLES					
NONE	20.04	N/A	38.34	6.85	65.23
NITROGEN	12.06	N/A	35.58	9.93	57.57
CARBON DIOXIDE	13.18	N/A	18.72	12.12	43.67
METHANE	13.54	N/A	39.42	9.71	62.67
EXPERIMENTAL TYPE 2 LOW PERMEABILITY SAMPLES					
NONE	11.94	N/A	48.05	13.49	73.48
NITROGEN	15.44	N/A	26.61	16.91	58.96
CARBON DIOXIDE	14.21	N/A	34.53	15.21	63.95
METHANE	13.80	N/A	41.24	15.53	70.57

* based on the result of a single run

Table 4.13

Results of oilflooding to Swi for Phase 3

RUN #	PORE VOLUME (CC)	POROSITY (%)	Kgas (md)	MASS OF WATER IN SAMPLE @ 100% SAT (g)	VOL OF WATER PRODUCED BY OILFLOOD (cc)	DENSITY OF WATER @ SG TEMP (g/cc)	MASS OF WATER IN SAMPLE AFTER OILFLOOD (g)	S_{wi} (%)
1	51.76	21.2	983.7	51.76	43.00	1.020	43.86	15.26
2	48.38	20.9	1004.8	48.38	41.81	1.020	42.65	11.85
3	42.33	17.5	112.0	42.33	32.41	1.017	32.96	22.13
4	43.82	17.9	114.0	43.82	33.46	1.020	34.12	22.13
5	48.15	20.2	797.5	48.15	38.75	1.014	39.29	18.40
6	49.95	20.9	804.6	49.95	40.40	1.017	41.09	17.74
7	42.38	17.6	109.2	42.38	35.16	1.000	35.16	17.03
8	45.49	18.7	109.6	45.49	37.11	1.017	37.74	17.03
9	53.64	22.0	800.8	53.64	44.96	1.005	45.18	15.76
10	51.80	21.6	834.6	51.80	43.64	1.000	43.64	15.76
11	41.39	17.6	108.3	41.39	33.11	1.014	33.57	18.88
12	44.32	18.3	111.4	44.32	36.51	1.020	37.24	15.97

Table 4.14

Thermal expansion rates and densities for the Athabasca bitumen saturated with nitrogen Phase 3

Temperature (C)	Thermal Expansion rates from 80 C (%)	Density (g/cc)
80	0.00	0.945
99	1.60	0.930
146	5.68	0.894
194	9.94	0.860

Table 4.15

Thermal expansion rates and densities for the Athabasca bitumen saturated with carbon dioxide
Phase 3

Temperature (C)	Thermal Expansion from 80 C (%)	Density (g/cc)
80	0.00	0.891
96	0.55	0.886
141	7.14	0.832
188	17.32	0.759
211	26.20	0.706
243	350.05	N/A*

(* not estimated due to out-gassing)

Table 4.16

Thermal expansion rates and densities for the Athabasca bitumen saturated with methane - Phase 3

Temperature (C)	Thermal Expansion rates from 80 C (%)	Density (g/cc)
80	0.00	0.912
98	0.39	0.908
144	4.70	0.871
190	21.58	0.750
216	38.56	0.658
247	254.05	N/A*

(* not estimated due to out-gassing)

Table 4.17

Result of the recoveries for all stages in Phase 3

RUN #	MASS OF ORIGINAL OIL IN PLACE (g)	MASS OF RECOVERY DUE TO HEAT UP (g)	PERCENT RECOVERY DUE TO HEAT UP AS %OOIP (% mass)	MASS OF RECOVERY DUE TO PRESS DDN (g)	PERCENT RECOVERY DUE TO PRESS DDN AS %OOIP (% mass)	MASS OF RECOVERY DUE TO STEAMFLD (g)	PERCENT RECOVERY DUE TO STEAMFLOOD AS %OOIP (% mass)
1	41.45	12.32	29.72	15.18	36.63	2.14	5.17
2	40.30	9.03	22.41	13.42	33.30	3.66	9.07
3	31.15	6.92	22.22	9.67	31.05	1.37	4.40
4	32.25	14.67	45.49	7.84	24.32	1.37	4.25
5	35.01	11.63	33.22	16.81	48.01	1.37	3.91
6	36.61	17.09	46.67	15.69	42.86	1.37	3.76
7	31.33	14.52	46.34	10.05	32.08	1.15	3.66
8	33.63	14.28	42.46	14.76	43.89	2.52	7.48
9	41.21	11.09	26.91	22.93	55.63	0.91	2.21
10	39.80	12.73	32.00	21.23	53.35	0.99	2.48
11	30.62	9.45	30.86	18.73	61.18	0.00	0.00
12	33.96	7.10	20.91	9.31	27.40	2.52	7.41

Types of oil used:

Runs #1-#4 : Athabasca bitumen saturated with nitrogen
Runs #5-#8 : Athabasca bitumen saturated with carbon dioxide
Runs #9-#12: Athabasca bitumen saturated with methane

Table 4.18

Summary of recoveries for all stages in Phase 3

RUN NUMBER	PERCENT RECOVERY DUE TO HEAT UP AS %OOIP (% mass)	PERCENT RECOVERY DUE TO PRESS DDN AS %OOIP (% mass)	PERCENT RECOVERY DUE TO STEAMFLD AS %OOIP (% mass)	PERCENT TOTAL RECOVERY AS %OOIP (% mass)
1	29.72	36.63	5.17	71.52
2	22.41	33.30	9.07	64.77
3	22.22	31.05	4.40	57.66
4	45.49	24.32	4.25	74.06
5	33.22	48.01	3.91	85.14
6	46.67	42.86	3.76	93.29
7	46.34	32.08	3.66	82.08
8	42.46	43.89	7.48	93.83
9	26.91	55.63	2.21	84.76
10	32.00	53.35	2.48	87.83
11	30.86	61.18	0.00	92.04
12	20.91	27.40	7.41	55.72

Type of oil used:

Runs #1-#4 : Nitrogen saturated Athabasca
Runs #5-#8 : Carbon dioxide saturated Athabasca
Runs #9-#12: Methane saturated Athabasca

Table 4.19

Results of the average recoveries for each pair run in Phase 3

HIGH PERMEABILITY SAMPLES

ADDITIVE SATURATED WITH ATHABASCA BITUMEN	**AVERAGE HEAT UP RECOVERY AS %OOIP**	**AVERAGE PRESSDDN RECOVERY AS %OOIP**	**AVERAGE STEAMFLD RECOVERY AS % OOIP**	**AVERAGE TOTAL RECOVERY AS %OOIP**
NITROGEN	26.07	34.97	7.12	68.16
CARBON DIOXIDE	39.95	45.44	3.84	89.23
METHANE	29.46	54.49	2.35	86.30
	LOW PERMEABILITY SAMPLES			
NITROGEN	22.22*	27.69	4.33	54.24
CARBON DIOXIDE	44.40	37.99	5.57	87.76
METHANE	25.89	44.29	3.71	73.89

* based on the result of one run

Table 4.20

Final results of the average recoveries for Phase 3

	HIGH PERMEABILITY SAMPLES			
ADDITIVE SATURATED WITH ATHABASCA BITUMEN	AVERAGE HEAT UP RECOVERY AS %OOIP	AVERAGE PRESSDDN RECOVERY AS %OOIP	AVERAGE STEAMFLD RECOVERY AS % OOIP	AVERAGE TOTAL RECOVERY AS %OOIP
NITROGEN	24.15	34.97	7.12	66.24
CARBON DIOXIDE	42.18	45.44	3.84	91.46
METHANE	27.68	54.49	2.35	84.52
	LOW PERMEABILITY SAMPLES			
NITROGEN	24.15*	27.69	4.33	56.17
CARBON DIOXIDE	42.18	37.99	5.57	85.54
METHANE	27.68	44.29	3.71	75.69

* based on the result of one run

Table 4.21

Mean Swi for each permeability group
Phase 4

Permeability group	No of samples used in the average	Average S_{wi} (%)
Low	12	21.93
Medium	7	17.84
High	3	18.04

Low permeability: Berea Sandstone
Medium permeability: Brown Sandstone
High permeability: Brown Sandstone

Table 4.22

Results of oilflooding stage in Phase 4

RUN #	PORE VOLUME (cc)	POROSITY (%)	Kgas (md)	MASS OF WATER IN SAMPLE @ 100% SAT (g)	VOLUME OF WATER PRODUCED BY OILFLD (g)	MASS OF WATER IN SAMPLE AFTER OILFLOODING (g)	Swi (%)
1	48.40	19.9	691.88	47.19	39.00	8.19	17.36
2	45.38	18.8	633.31	44.25	34.00	10.25	23.16
3	49.10	20.3	83.06	47.87	34.31	13.56	28.33
4	43.73	18.4	83.89	42.64	33.28	9.36	21.95
5	47.68	20.6	832.27	46.49	40.00	6.49	13.96
6	52.63	22.4	948.82	51.31	42.16	9.16	17.84
7	45.53	19.1	74.49	44.39	34.65	9.74	21.95
8	40.57	17.2	74.74	39.56	30.08	9.48	23.96
9	54.27	22.4	1628.1	52.91	43.37	9.54	18.04
10	50.65	21.7	1648.4	49.38	40.47	8.91	18.04
11	41.84	17.8	83.41	40.79	28.70	12.09	29.64
12	39.74	17.0	82.14	38.75	30.50	8.25	21.29
13	55.03	22.8	1237.6	53.65	44.30	9.35	17.43
14	47.35	20.4	1595.0	46.17	37.84	8.33	18.04
15	39.97	17.2	78.79	38.77	30.26	8.51	21.95
16	41.98	18.3	76.26	40.93	31.95	8.99	21.95
17	49.16	21.4	2340.6	47.93	38.95	8.98	18.74
18	55.66	22.3	1750.0	54.27	44.53	9.74	17.95
19	45.68	18.9	144.94	44.55	36.10	8.45	18.97
20	40.35	17.5	102.38	39.34	31.90	7.44	18.91
21	51.75	22.2	3533.6	50.45	41.73	8.72	17.28
22	52.09	22.1	3548.4	50.79	42.83	7.96	15.67
23	47.54	20.3	98.12	46.35	36.73	9.62	20.76
24	42.28	17.9	119.25	41.22	32.41	8.81	21.37
25	53.45	22.3	879.53	52.11	40.29	11.82	22.68
26	49.94	21.2	709.71	48.69	41.35	7.34	15.07
27	42.37	18.5	97.29	41.31	31.60	9.71	23.51
28	42.27	18.2	97.24	41.21	32.05	9.16	22.23
29	47.39	20.5	639.68	46.22	38.00	8.22	17.78
30	46.88	20.3	628.14	45.70	38.92	6.78	14.84
31	43.62	18.8	97.73	42.53	33.20	9.33	21.94
32	41.28	18.3	97.47	40.25	34.19	6.06	15.06

Table 4.23

Thermal expansion rates for live Lloydminster crude and distilled water at 10 Mpa - Phase 4

Temp (C)	Volume of oil in system (cc)	Thermal Expansion rates for oil from 80 C (%)	Thermal Expansion rates for water from 80 C (%)
80	346.6	0.00	0.00
100	352.3	1.65	1.25
120	358.0	3.30	2.85
140	363.0	4.72	4.84
160	368.0	6.41	6.91
180	374.1	7.93	9.55
200	381.2	9.97	11.94
225	390.6	12.70	15.93
250	424.9	22.60	20.97

Table 4.24

Densities for "Live" Lloydminster crude

Temperature (C)	Live Lloydminister density (g/cc)
25	0.837
80	0.804
100	0.791
120	0.778
140	0.767
160	0.755
180	0.745
200	0.731
225	0.713

Table 4.25

Results of the heat up stage in Phase 4

RUN NUMBER	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS OF RECOVERY DUE TO HEAT UP (g)	PERCENT RECOVERY DUE TO HEAT UP AS %OOIP (% mass)
1	48.40	32.16	8.73	27.13
2	45.38	28.04	10.69	38.13
3	49.10	28.29	7.90	27.91
4	43.73	27.44	6.72	24.47
5	47.68	32.98	11.45	34.70
6	52.63	34.76	8.75	25.16
7	45.53	28.57	5.20	18.22
8	40.57	24.80	6.95	28.01
9	54.27	35.76	N/A	N/A
10	50.65	33.37	6.40	19.19
11	41.84	23.67	10.36	43.77
12	39.74	25.15	10.43	41.48
13	55.03	36.53	7.95	21.75
14	47.35	31.21	6.82	21.86
15	39.97	24.95	6.86	27.51
16	41.98	26.34	7.24	27.50
17	49.16	32.12	9.29	28.92
18	55.66	36.72	15.39	41.90
19	45.68	29.77	9.02	30.31
20	40.35	26.31	13.48	51.23
21	51.75	34.41	5.84	16.97
22	52.09	35.32	6.37	18.03
23	47.54	30.29	5.94	19.60
24	42.28	26.73	4.95	18.52
25	53.45	33.22	9.58	28.83
26	49.94	34.10	9.58	28.11
27	42.37	26.06	8.82	33.86
28	42.27	26.43	6.47	24.49
29	47.39	31.34	8.63	27.55
30	46.88	32.09	8.43	26.27
31	43.62	27.38	6.07	22.18
32	41.28	28.19	7.94	28.17

N/A not measured

Table 4.26

Densities of "partially live" Lloydminster Crude

Temperature (C)	Average Density (g/cc)
25	0.920
80	0.890
100	0.877
120	0.863
140	0.849
160	0.834
180	0.818
200	0.801
225	0.777

Table 4.27

Results of the waterflooding stage in Phase 4

RUN NUMBER	TYPE OF ADDITIVE USED	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS RECOVERY DUE TO WATERFLOOD (g)	PERCENT RECOVERY DUE TO WATERFLOOD AS %OOIP (% mass)
1	NONE	48.40	32.16	7.46	23.20
2	NONE	45.38	28.04	4.32	15.39
3	NONE	49.10	28.29	3.81	13.47
4	NONE	43.73	27.44	5.29	19.26
9	NITROGEN	54.27	35.76	7.64	21.36
10	NITROGEN	50.65	33.37	8.90	26.67
11	NITROGEN	41.84	23.67	5.52	23.31
12	NITROGEN	39.74	25.15	6.35	25.25
17	CARBON DIOXIDE	49.16	32.12	3.62	11.28
18	CARBON DIOXIDE	55.66	36.72	1.90	5.17
19	CARBON DIOXIDE	45.68	29.77	3.16	10.63
20	CARBON DIOXIDE	40.35	26.31	3.64	13.83
25	METHANE	53.45	33.22	8.34	25.11
26	METHANE	49.94	34.10	8.98	26.34
27	METHANE	42.37	26.06	6.62	25.42
28	METHANE	42.27	26.43	8.78	33.22

Table 4.28

Results of the pressure drawdown stage in Phase 4

RUN NUMBER	TYPE OF ADDITIVE USED IN WATERFLOOD	EXPRMNT'L TYPE	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS RECOVERY DUE TO PRESSDDN (g)	PERCENT RECOVERY DUE TO PRESSDDN AS %OOIP (% mass)
1	NONE	1	48.40	32.16	6.57	20.43
2	NONE	1	45.38	28.04	4.91	17.51
3	NONE	1	49.10	28.29	3.05	10.79
4	NONE	1	43.73	27.44	7.91	28.81
5	NONE	2	47.68	32.98	11.38	34.51
6	NONE	2	52.63	34.76	16.15	46.47
7	NONE	2	45.53	28.57	8.59	30.07
8	NONE	2	40.57	24.80	4.48	18.06
9	NITROGEN	1	54.27	35.76	6.52	18.25
10	NITROGEN	1	50.65	33.37	3.87	11.58
11	NITROGEN	1	41.84	23.67	1.22	5.17
12	NITROGEN	1	39.74	25.15	2.03	8.08
13	NITROGEN	2	55.03	36.53	10.15	27.79
14	NITROGEN	2	47.35	31.21	9.16	29.35
15	NITROGEN	2	39.97	24.95	8.35	33.48
16	NITROGEN	2	41.98	26.34	8.10	30.77
17	CARBON DIOXIDE	1	49.16	32.12	3.45	10.73
18	CARBON DIOXIDE	1	55.66	36.72	7.32	19.93
19	CARBON DIOXIDE	1	45.68	29.77	2.82	9.47
20	CARBON DIOXIDE	1	40.35	26.31	1.23	4.66
21	CARBON DIOXIDE	2	51.75	34.41	15.95	46.36
22	CARBON DIOXIDE	2	52.09	35.32	17.89	50.64
23	CARBON DIOXIDE	2	47.54	30.29	6.46	21.34
24	CARBON DIOXIDE	2	42.28	26.73	10.49	39.26
25	METHANE	1	53.45	33.22	4.10	12.35
26	METHANE	1	49.94	34.10	6.15	18.05
27	METHANE	1	42.37	26.06	4.11	15.76
28	METHANE	1	42.27	26.43	4.31	16.32
29	METHANE	2	47.39	31.34	13.55	43.26
30	METHANE	2	46.88	32.09	11.73	36.55
31	METHANE	2	43.62	27.38	6.99	25.53
32	METHANE	2	41.28	28.19	9.46	33.54

Table 4.29

Results of the steamflooding stage in Phase 4

RUN NUMBER	TYPE OF ADDITIVE USED IN WATERFLOOD	EXPRMNT'L TYPE	PORE VOLUME (cc)	MASS OF ORIGINAL OIL IN PLACE (g)	MASS RECOVERY DUE TO STEAMFLD (g)	PERCENT RECOVERY DUE TO STEAMFLOOD AS %OOIP (% mass)
1	NONE	1	48.40	32.16	2.89	8.97
2	NONE	1	45.38	28.04	0.88	3.15
3	NONE	1	49.10	28.29	1.32	4.66
4	NONE	1	43.73	27.44	1.98	7.23
5	NONE	2	47.68	32.98	2.64	8.01
6	NONE	2	52.63	34.76	2.41	6.95
7	NONE	2	45.53	28.57	0.94	3.30
8	NONE	2	40.57	24.80	1.99	8.03
9	NITROGEN	1	54.27	35.76	3.08	8.60
10	NITROGEN	1	50.65	33.37	1.76	5.26
11	NITROGEN	1	41.84	23.67	1.76	7.44
12	NITROGEN	1	39.74	25.15	1.54	6.14
13	NITROGEN	2	55.03	36.53	2.41	6.60
14	NITROGEN	2	47.35	31.21	2.06	6.61
15	NITROGEN	2	39.97	24.95	3.73	14.96
16	NITROGEN	2	41.98	26.34	2.21	8.38
17	CARBON DIOXIDE	1	49.16	32.12	2.20	6.85
18	CARBON DIOXIDE	1	55.66	36.72	1.97	5.38
19	CARBON DIOXIDE	1	45.68	29.77	2.06	6.92
20	CARBON DIOXIDE	1	40.35	26.31	2.00	7.59
21	CARBON DIOXIDE	2	51.75	34.41	2.88	8.37
22	CARBON DIOXIDE	2	52.09	35.32	1.93	5.47
23	CARBON DIOXIDE	2	47.54	30.29	5.25	17.34
24	CARBON DIOXIDE	2	42.28	26.73	2.41	9.02
25	METHANE	1	53.45	33.22	3.10	9.34
26	METHANE	1	49.94	34.10	2.89	8.47
27	METHANE	1	42.37	26.06	3.11	11.95
28	METHANE	1	42.27	26.43	2.66	10.08
29	METHANE	2	47.39	31.34	3.55	11.32
30	METHANE	2	46.88	32.09	1.56	4.86
31	METHANE	2	43.62	27.38	3.10	11.33
32	METHANE	2	41.28	28.19	2.89	10.24

Table 4.30

Summary of the recoveries for all stages in Phase 4

RUN #	TYPE OF ADDITIVE USED IN WATERFLOOD	EXPRMNT TYPE	RECOVERY DUE TO HEAT UP AS %OOIP (% mass)	RECOVERY DUE TO WATERFLOOD AS %OOIP (% mass)	RECOVERY DUE TO PRESSDDN AS %OOIP (% mass)	RECOVERY DUE TO STEAMFLOOD AS %OOIP (% mass)	TOTAL RECOVERY AS %OOIP (% mass)
1	NONE	1	27.13	23.20	20.43	8.97	79.73
2	NONE	1	38.13	15.39	17.51	3.15	74.18
3	NONE	1	27.91	13.47	10.79	4.66	56.83
4	NONE	1	24.47	19.26	28.81	7.23	79.77
5	NONE	2	34.70	N/A	34.51	8.01	77.22
6	NONE	2	25.16	N/A	46.47	6.95	78.58
7	NONE	2	18.22	N/A	30.07	3.30	51.59
8	NONE	2	28.01	N/A	18.06	8.03	54.10
9	NITROGEN	1	N/A	21.36	18.25	8.60	48.21
10	NITROGEN	1	19.19	26.67	11.58	5.26	62.70
11	NITROGEN	1	43.77	23.31	5.17	7.44	79.69
12	NITROGEN	1	41.48	25.25	8.08	6.14	80.95
13	NITROGEN	2	21.75	N/A	27.79	6.60	56.14
14	NITROGEN	2	21.86	N/A	29.35	6.61	57.82
15	NITROGEN	2	27.51	N/A	33.48	14.96	75.95
16	NITROGEN	2	27.50	N/A	30.77	8.38	66.65
17	CARBON DIOX	1	28.92	11.28	10.73	6.85	57.78
18	CARBON DIOX	1	41.90	5.17	19.93	5.38	72.38
19	CARBON DIOX	1	30.31	10.63	9.47	6.92	57.33
20	CARBON DIOX	1	51.23	13.83	4.66	7.59	77.31
21	CARBON DIOX	2	16.97	N/A	46.36	8.37	71.70
22	CARBON DIOX	2	18.03	N/A	50.64	5.47	74.14
23	CARBON DIOX	2	19.60	N/A	21.34	17.34	58.28
24	CARBON DIOX	2	18.52	N/A	39.26	9.02	66.80
25	METHANE	1	28.83	25.11	12.35	9.34	75.63
26	METHANE	1	28.11	26.34	18.05	8.47	80.97
27	METHANE	1	33.86	25.42	15.76	11.95	86.99
28	METHANE	1	24.49	33.22	16.32	10.08	84.11
29	METHANE	2	27.55	N/A	43.26	11.32	82.13
30	METHANE	2	26.27	N/A	36.55	4.86	67.68
31	METHANE	2	22.18	N/A	25.53	11.33	59.04
32	METHANE	2	28.17	N/A	33.54	10.24	71.95

Table 4.31

Results of the average recoveries for Phase 4

ADDITIIVE	AVERAGE HEAT UP RECOVERY AS %OOIP	AVERAGE WATERFLOOD RECOVERY AS %OOIP	AVERAGE PRESSDDN RECOVERY AS %OOIP	AVERAGE STEAMFLOOD RECOVERY AS %OOIP	AVERAGE TOTAL RECOVERY AS %OOIP
	EXPERIMENTAL TYPE 1 HIGH PERMEABILITY SAMPLES				
NONE	32.63	19.3	18.97	6.06	76.96
NITROGEN	19.19 *	24.02	14.92	6.93	65.06
CARBON DIOXIDE	35.41 [a]	8.23 [a]	15.33 [a]	6.12 [a]	65.09 [a]
METHANE	28.47	25.73	15.2	8.91	78.31
	EXPERIMENTAL TYPE 1 LOW PERMEABILITY SAMPLES				
NONE	26.19	16.37	19.8	5.95	68.31
NITROGEN	42.63	24.28	6.63	6.79	80.33
CARBON DIOXIDE	40.77 [a]	12.23 [a]	7.07 [a]	7.26 [a]	67.33
METHANE	29.18	29.32	16.04	11.02	85.56
	EXPERIMENTAL TYPE 2 HIGH PERMEABILITY SAMPLES				
NONE	29.93	N/A	40.49	7.48	77.90
NITROGEN	21.81	N/A	28.57	6.61	56.99
CARBON DIOXIDE	17.50 [b]	N/A	48.50 [b]	6.92 [b]	72.92 [b]
METHANE	26.91	N/A	39.91	8.09	74.91
	EXPERIMENTAL TYPE 2 LOW PERMEABILITY SAMPLES				
NONE	23.12	N/A	24.07	5.67	52.86
NITROGEN	27.51	N/A	32.13	11.67	71.31
CARBON DIOXIDE	19.06 [b]	N/A	30.3 [b]	13.18 [b]	62.54 [b]
METHANE	25.18	N/A	29.54	10.79	65.51

* based on the result of one run

[a] "live" oil bubble point pressure = 5.1 Mpa, operating pressure = 5.8 Mpa

[b] "live" oil bubble point pressure = 5.1 Mpa, operating pressure = 8.5 Mpa

Table 4.32

Final results of the average recoveries for Phase 4

EXPERIMENTAL TYPE 1
HIGH PERMEABILITY SAMPLES

ADDITIIVE	AVERAGE HEAT UP RECOVERY AS %OOIP	AVERAGE WATERFLOOD RECOVERY AS %OOIP	AVERAGE PRESSDDN RECOVERY AS %OOIP	AVERAGE STEAMFLOOD RECOVERY AS %OOIP	AVERAGE TOTAL RECOVERY AS %OOIP
NONE	27.73	19.30	18.97	6.06	72.06
NITROGEN	27.73 *	24.02	14.92	6.93	73.60
CARBON DIOXIDE	38.09 [a]	8.23 [a]	15.33 [a]	6.12 [a]	67.77 [a]
METHANE	27.73	25.73	15.20	8.91	77.57
	EXPERIMENTAL TYPE 1 LOW PERMEABILITY SAMPLES				
NONE	27.73	16.37	19.80	5.95	69.85
NITROGEN	27.73	24.28	6.63	6.79	65.43
CARBON DIOXIDE	38.09 [a]	12.23 [a]	7.07 [a]	7.26 [a]	64.65 [a]
METHANE	27.73	29.32	16.04	11.02	84.11
	EXPERIMENTAL TYPE 2 HIGH PERMEABILITY SAMPLES				
NONE	27.73	N/A	36.32	7.48	71.53
NITROGEN	27.73	N/A	36.32	6.61	70.66
CARBON DIOXIDE	18.28 [b]	N/A	48.50 [b]	6.92 [b]	73.70 [b]
METHANE	27.73	N/A	36.32	8.09	72.14
	EXPERIMENTAL TYPE 2 LOW PERMEABILITY SAMPLES				
NONE	27.73	N/A	28.85	5.67	61.98
NITROGEN	27.73	N/A	28.58	11.67	67.98
CARBON DIOXIDE	18.28 [b]	N/A	30.30 [b]	13.18 [b]	62.30 [b]
METHANE	27.73	N/A	28.58	10.79	67.10

* based on the result of one run
[a] "live" oil bubble point pressure = 5.1 Mpa, operating pressure = 5.8 Mpa
[b] "live" oil bubble point pressure = 5.1 Mpa, operating pressure = 8.5 Mpa

Table 5.1

Differences in recoveries from the baseline runs in Phase 2

EXPERIMENTAL TYPE 1

PROCESS	HIGH PERMEABILITY			LOW PERMEABILITY		
	Nitrogen	Carbon Dioxide	Methane	Nitrogen	Carbon Dioxide	Methane
HEAT UP	0.00	0.00	0.00	0.00	0.00	0.00
WATERFLOODING	+1.62	+6.30	-1.26	+10.21	+5.45	+24.03
PRESSURE DDWN	-8.75	-14.92	-5.09	+4.99	+6.47	-7.33
STEAMFLOODING	+6.59	+4.51	-2.49	-8.74	-4.82	-7.51

EXPERIMENTAL TYPE 2

	HIGH PERMEABILITY			LOW PERMEABILITY		
	Nitrogen	Carbon Dioxide	Methane	Nitrogen	Carbon Dioxide	Methane
HEAT UP	0.00	0.00	0.00	0.00	0.00	0.00
WATERFLOODING	N/A	N/A	N/A	N/A	N/A	N/A
PRESSURE DDWN	0.00	0.00	0.00	0.00	0.00	0.00
STEAMFLOODING	+3.08	+4.92	+2.86	+3.42	+1.72	+2.04

+ indicates improvement over baseline recovery
- indicates impairment from baseline recovery
N/A no waterflooding in Experimental Type 2

Table 5.2

Differences in recoveries from the baseline runs for Phase 3

PROCESS	HIGH PERMEABILITY			LOW PERMEABILITY		
	Nitrogen	Carbon Dioxide	Methane	Nitrogen	Carbon Dioxide	Methane
HEAT UP	+11.91	+25.79	+15.30	+8.06	+30.24	+11.73
PRESSURE DRAWDOWN	+1.95	+12.42	+21.47	-9.92	+0.38	+6.69
STEAMFLOODING	+0.27	-3.01	-4.50	-9.16	-8.12	-9.78

+ indicates improvement over baseline recovery
- indicates impairment from baseline recovery

Table 5.3

Differences in recoveries from the baseline runs in Phase 4

EXPERIMENTAL TYPE 1

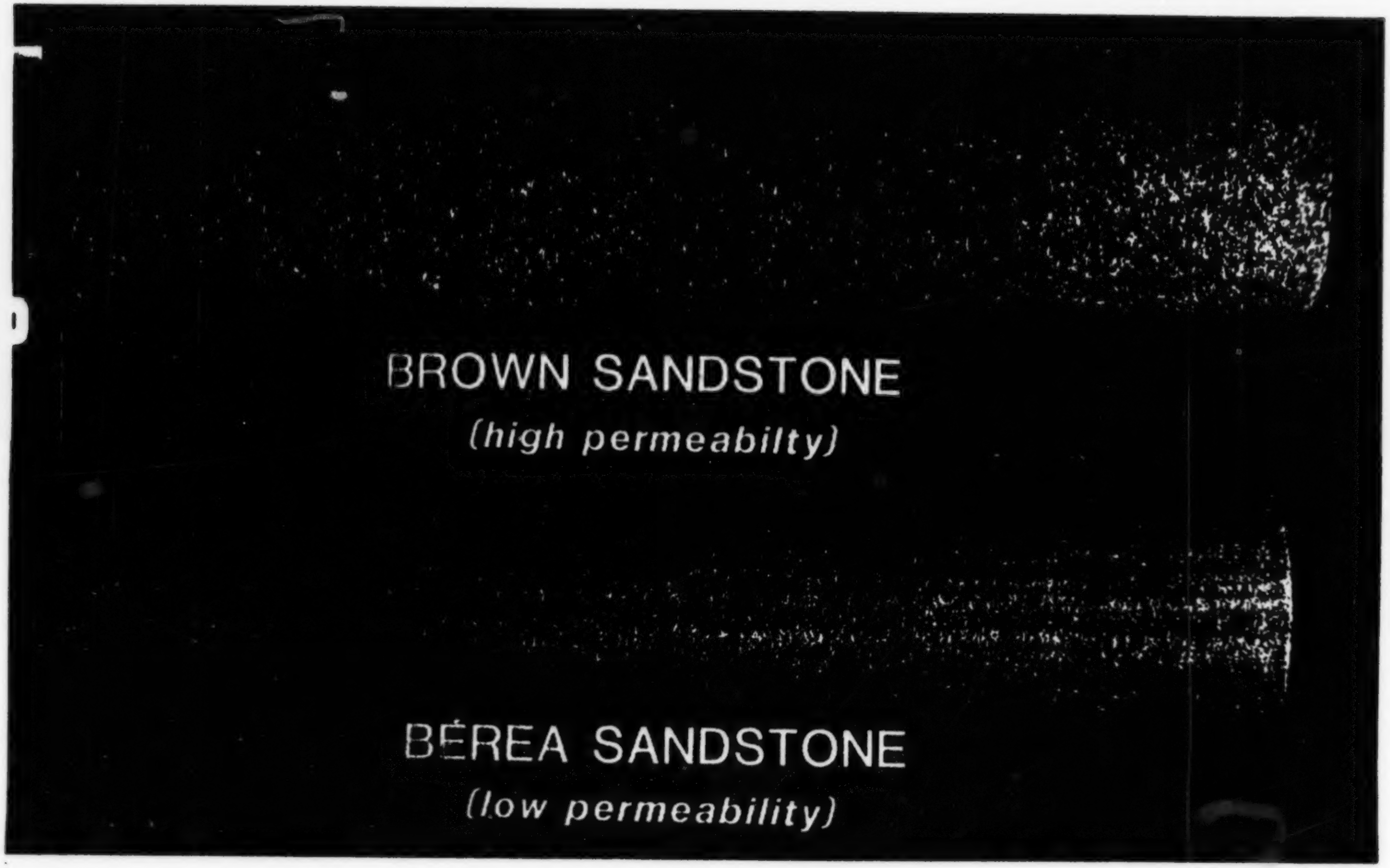
PROCESS	HIGH PERMEABILITY			LOW PERMEABILITY		
	Nitrogen	Carbon Dioxide	Methane	Nitrogen	Carbon Dioxide	Methane
HEAT UP	0.00	+10.36	0.00	0.00	+10.36	0.00
WATERFLOODING	+4.72	-11.07	+6.43	+7.91	-4.14	+12.95
PRESSURE DDWN	-4.05	-3.64	-3.71	-13.17	-12.73	-3.76
STEAMFLOODING	+0.87	+0.06	+2.85	+0.84	+1.31	+5.07

EXPERIMENTAL TYPE 2

	HIGH PERMEABILITY			LOW PERMEABILITY		
	Nitrogen	Carbon Dioxide	Methane	Nitrogen	Carbon Dioxide	Methane
HEAT UP	0.00	-9.45	0.00	0.00	-9.45	0.00
WATERFLOODING	N/A	N/A	N/A	N/A	N/A	N/A
PRESSURE DDWN	0.00	+12.18	0.00	0.00	+12.18	0.00
STEAMFLOODING	+0.87	-0.56	+0.61	+0.60	+7.51	+5.12

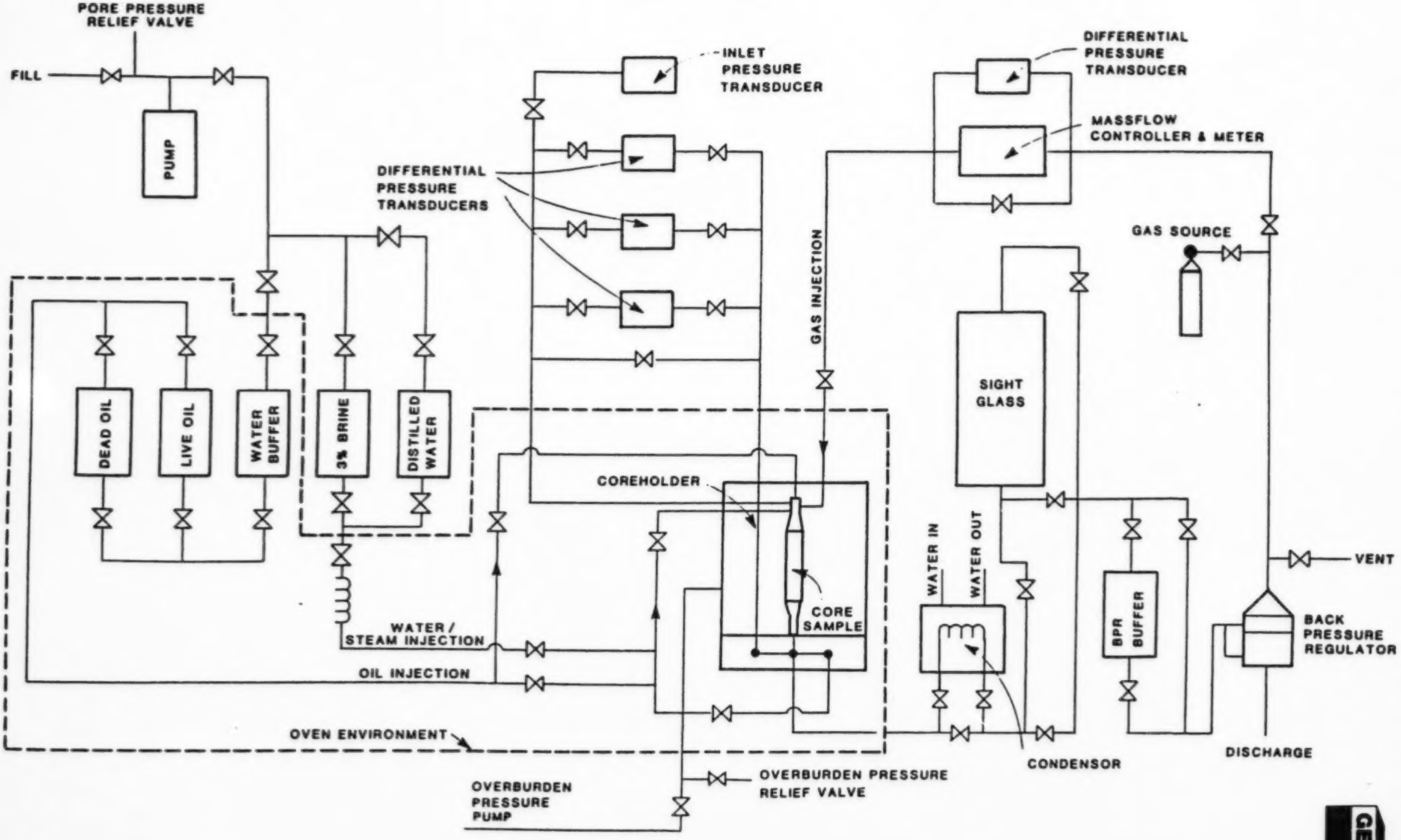
+ indicates improvement over baseline recovery
- indicates impairment from baseline recovery
N/A no waterflooding in Experimental Type 2

Figure 2.1


BROWN SANDSTONE
(high permeabilty)
BEREA SANDSTONE
(low permeability)

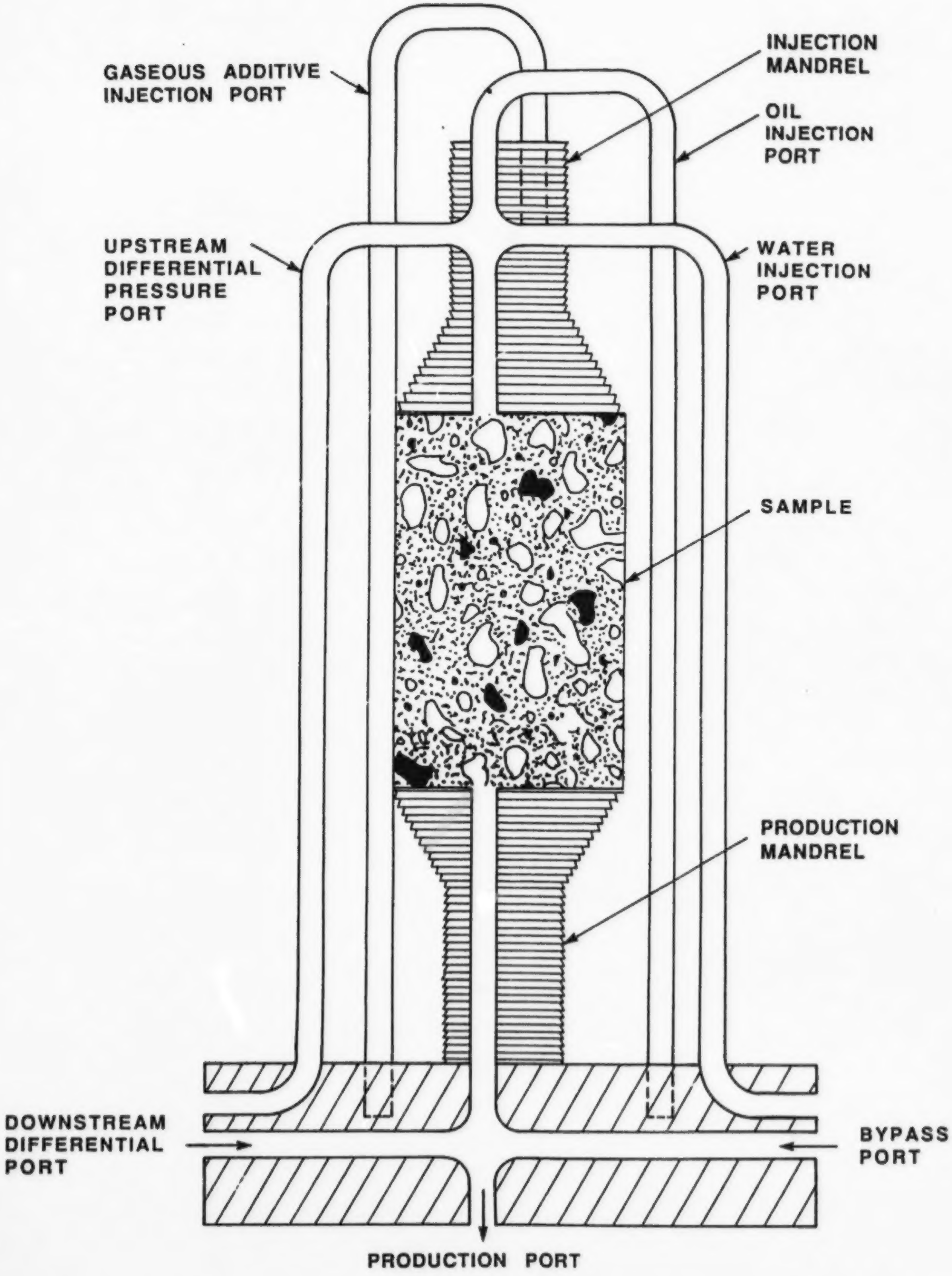
CORE SAMPLES

Figure 3.1


PORE PRESSURE RELIEF VALVE
FILL
PUMP
DIFFERENTIAL PRESSURE TRANSDUCERS
INLET PRESSURE TRANSDUCER
DIFFERENTIAL PRESSURE TRANSDUCER
MASSFLOW CONTROLLER & METER
GAS SOURCE
GAS INJECTION
SIGHT GLASS
DEAD OIL
LIVE OIL
WATER BUFFER
3% BRINE
DISTILLED WATER
COREHOLDER
CORE SAMPLE
WATER IN
WATER OUT
BPR BUFFER
VENT
BACK PRESSURE REGULATOR
WATER / STEAM INJECTION
OIL INJECTION
OVEN ENVIRONMENT
CONDENSOR
DISCHARGE
OVERBURDEN PRESSURE PUMP
OVERBURDEN PRESSURE RELIEF VALVE

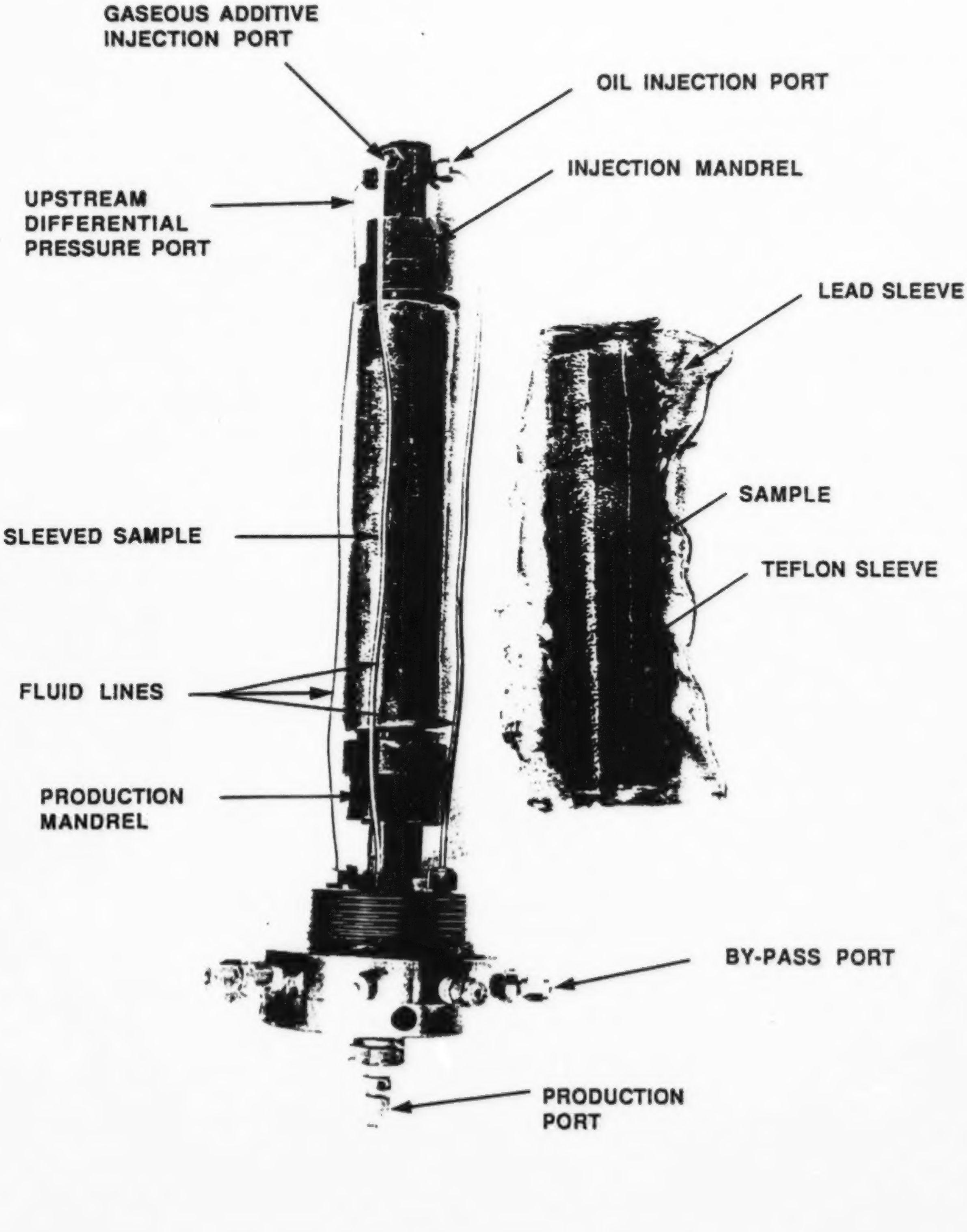
STEAM WITH ADDITIVES DISPLACEMENT APPARATUS

Figure 3.2


GASEOUS ADDITIVE INJECTION PORT
INJECTION MANDREL
OIL INJECTION PORT
UPSTREAM DIFFERENTIAL PRESSURE PORT
WATER INJECTION PORT
SAMPLE
PRODUCTION MANDREL
DOWNSTREAM DIFFERENTIAL PORT
BYPASS PORT
PRODUCTION PORT

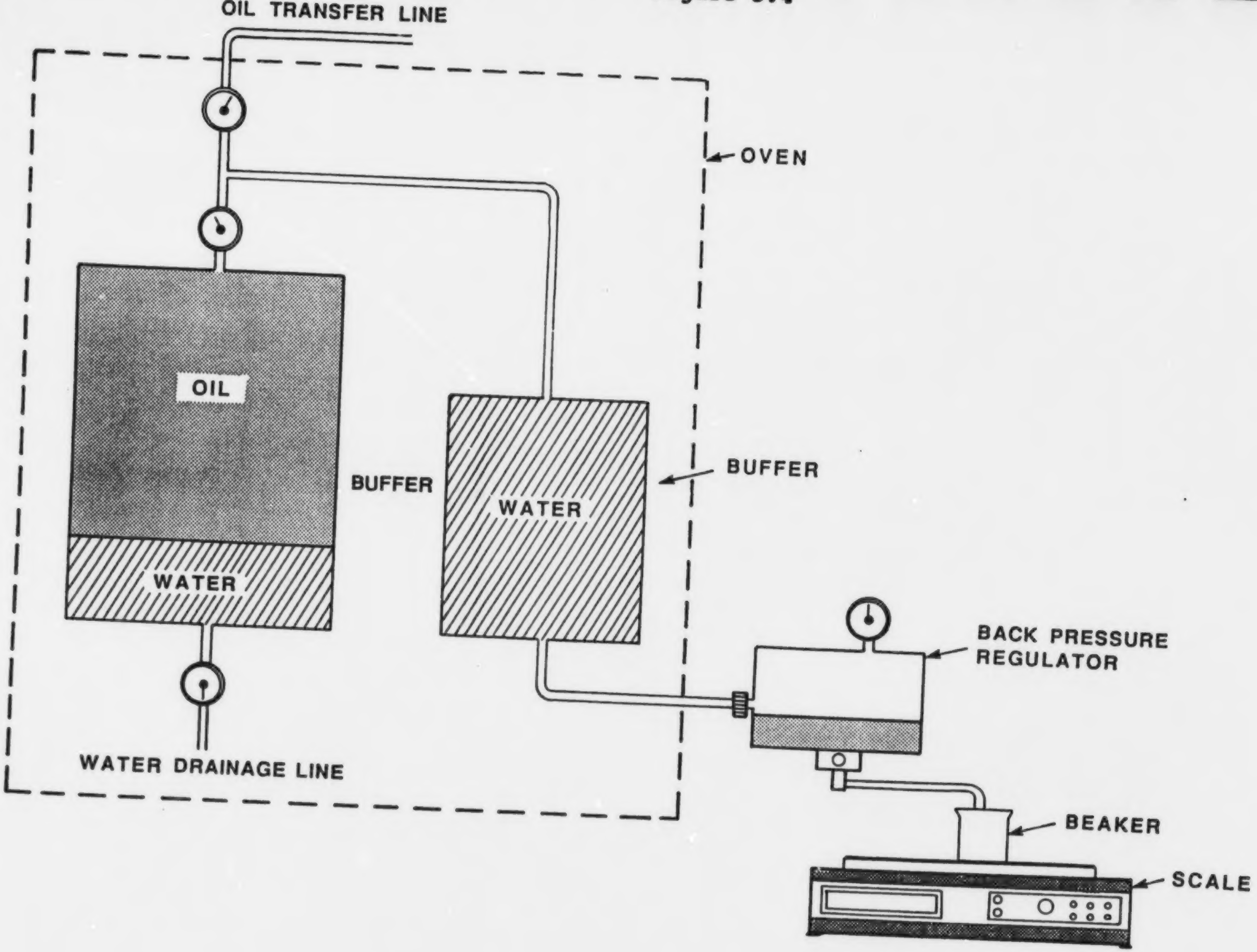
SAMPLE / MANDREL ASSEMBLY

Figure 3.3


GASEOUS ADDITIVE INJECTION PORT
OIL INJECTION PORT
INJECTION MANDREL
UPSTREAM DIFFERENTIAL PRESSURE PORT
LEAD SLEEVE
SAMPLE
SLEEVED SAMPLE
TEFLON SLEEVE
FLUID LINES
PRODUCTION MANDREL
BY-PASS PORT
PRODUCTION PORT

SAMPLE / MANDREL ASSEMBLY

Figure 3.4


OIL TRANSFER LINE
OVEN
OIL
WATER
BUFFER
WATER
BUFFER
WATER DRAINAGE LINE
BACK PRESSURE REGULATOR
BEAKER
SCALE

APPARATUS FOR MEASURING THERMAL EXPANSION OF OIL

Figure 4.1

Thermal Expansion Rates for 3% brine

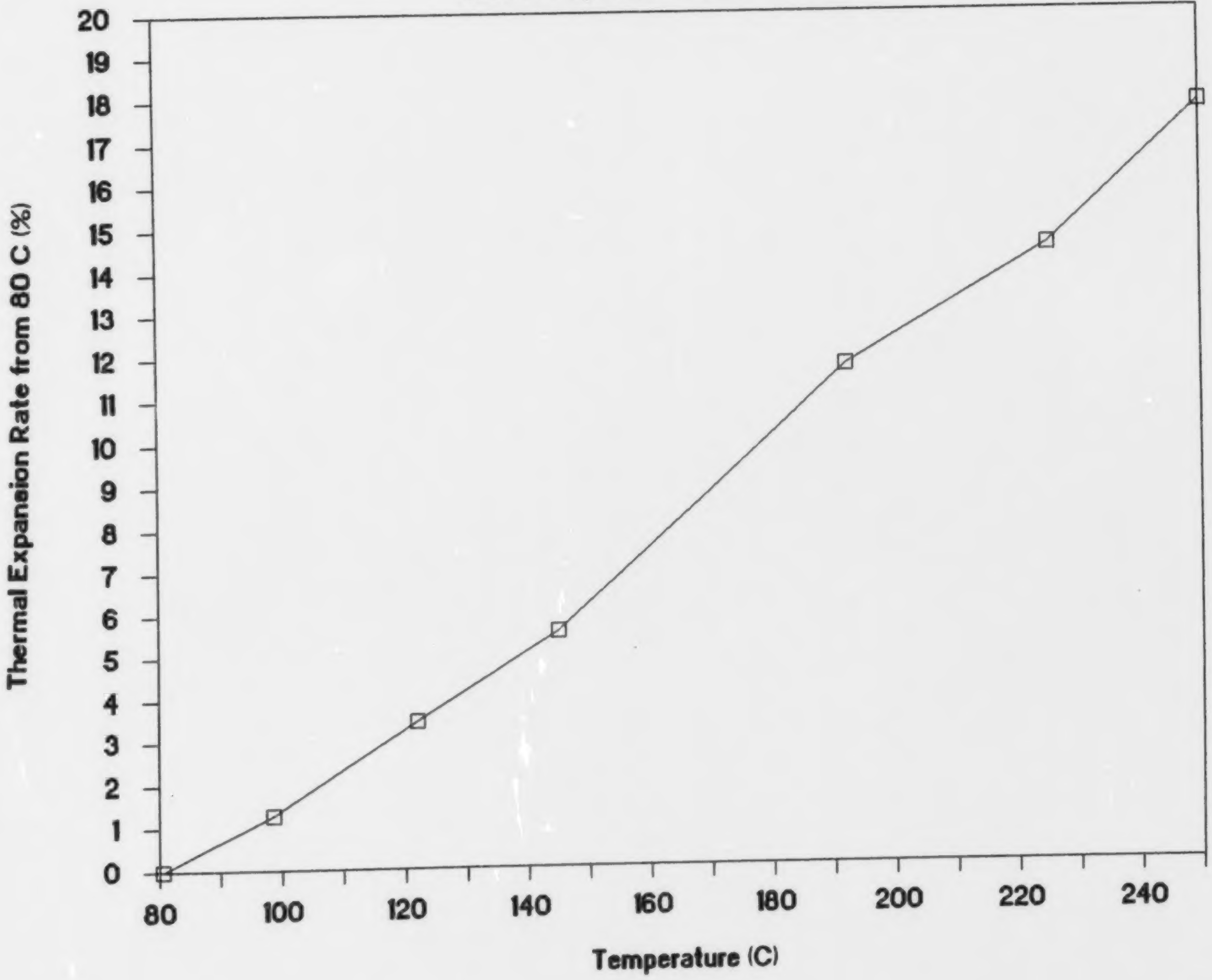


Figure 4.2

Thermal Expansion Rates for Athabasca

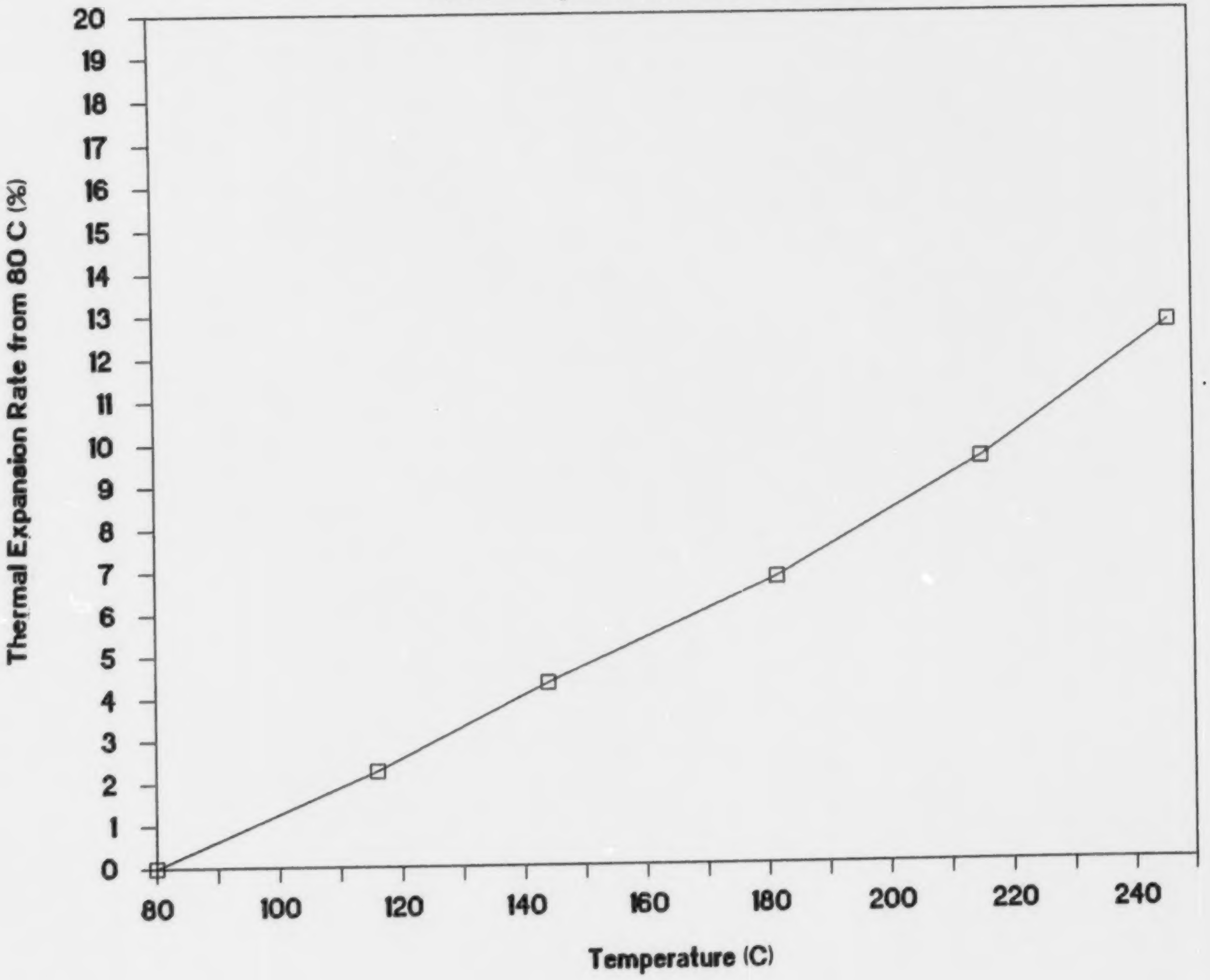


Figure 4.3

Thermal Expansion Rates for Water

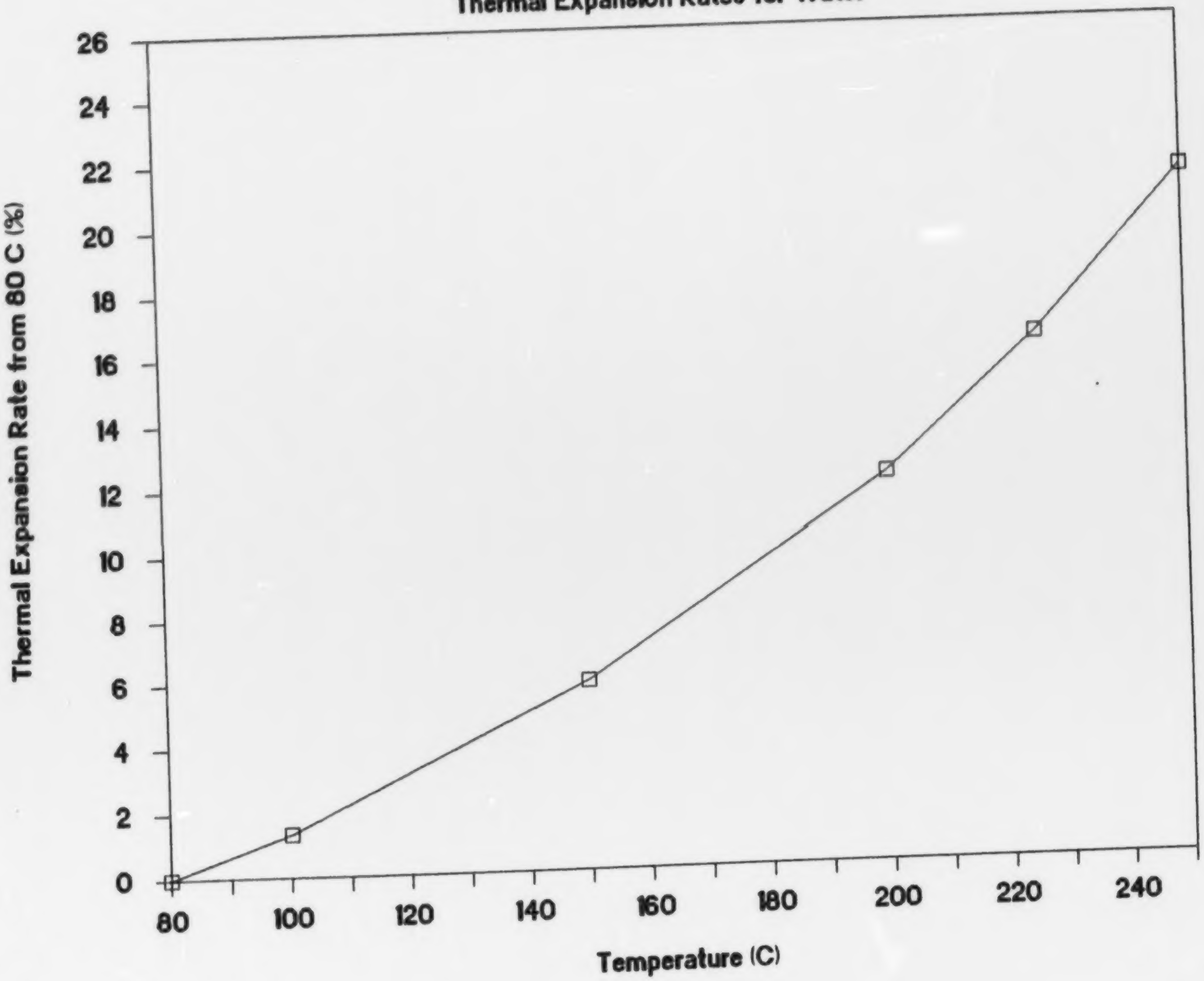


Figure 4.4

Density of Athabasca bitumen

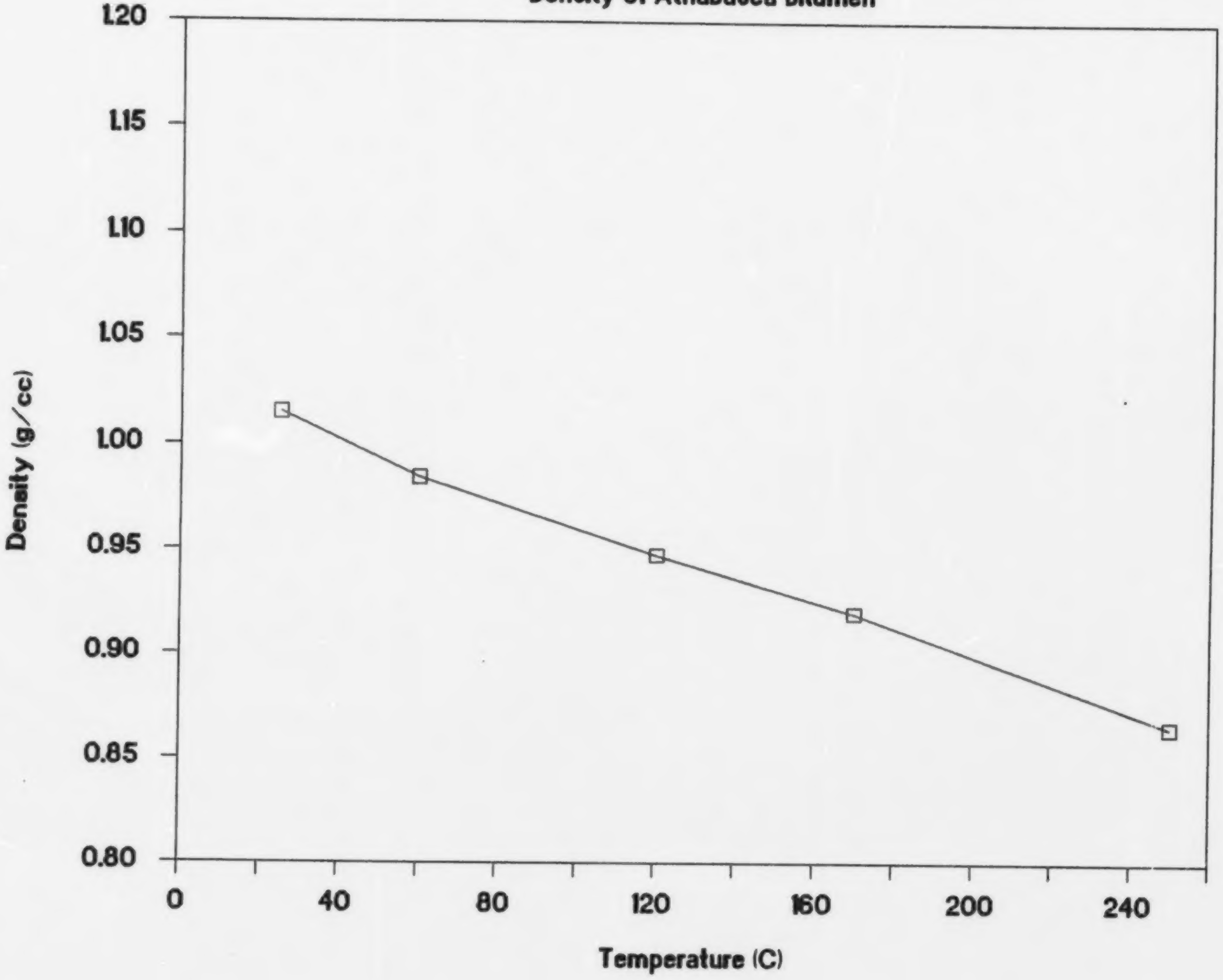


Figure 4.5

Thermal Expansion Rates for Athabasca

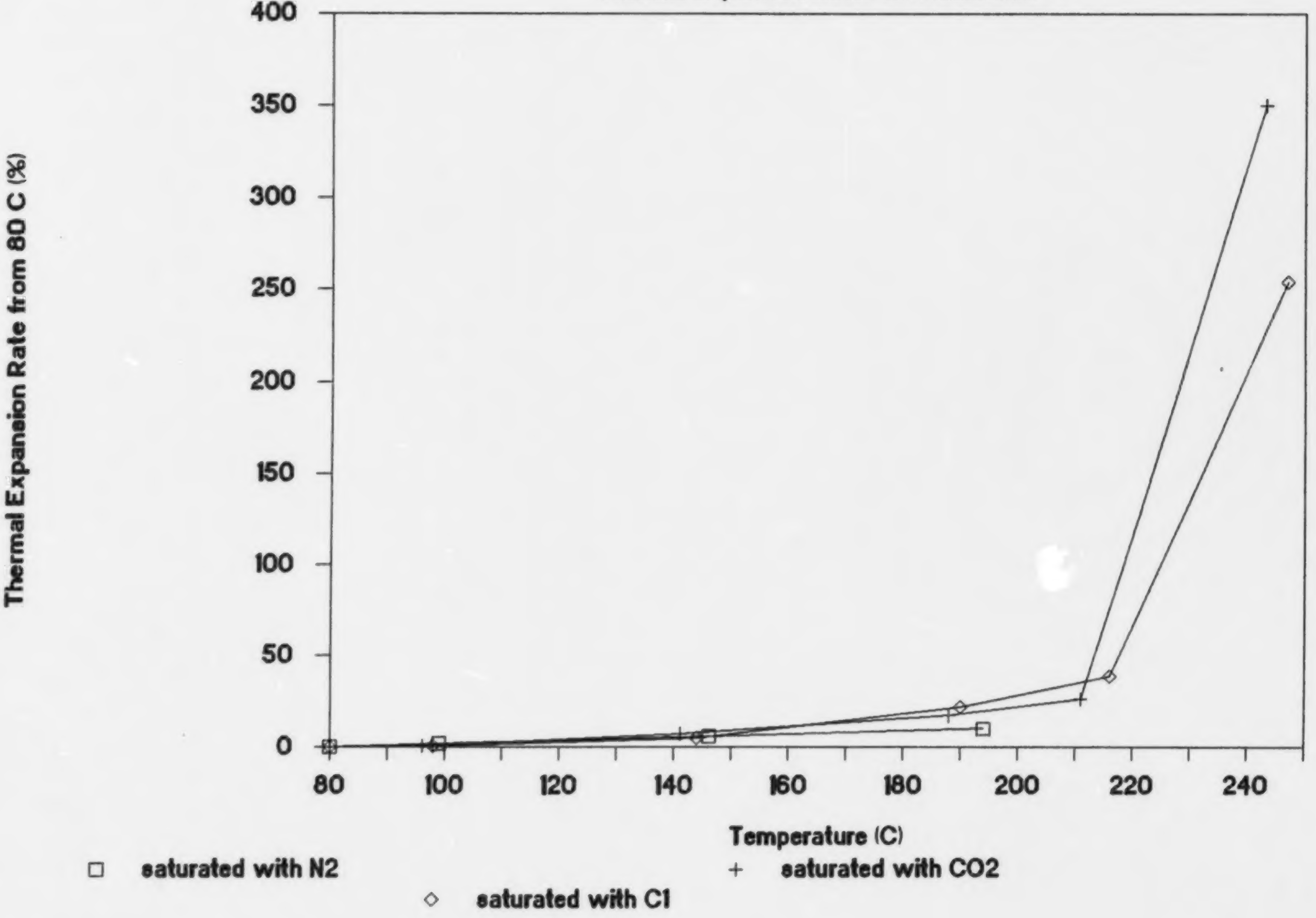


Figure 4.6

Densities for saturated Athabasca

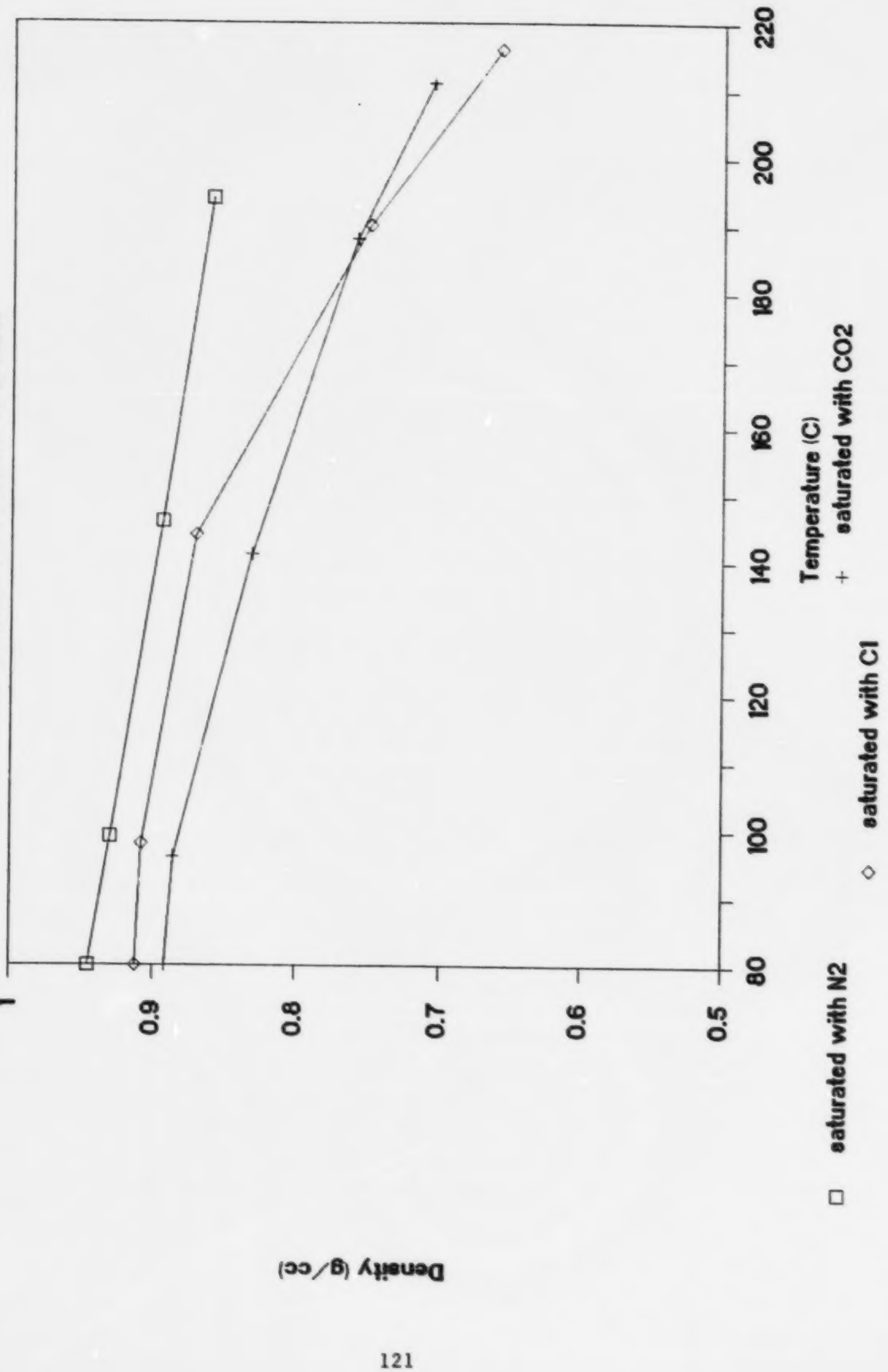


Figure 4.7

Live Lloydminster crude & Water

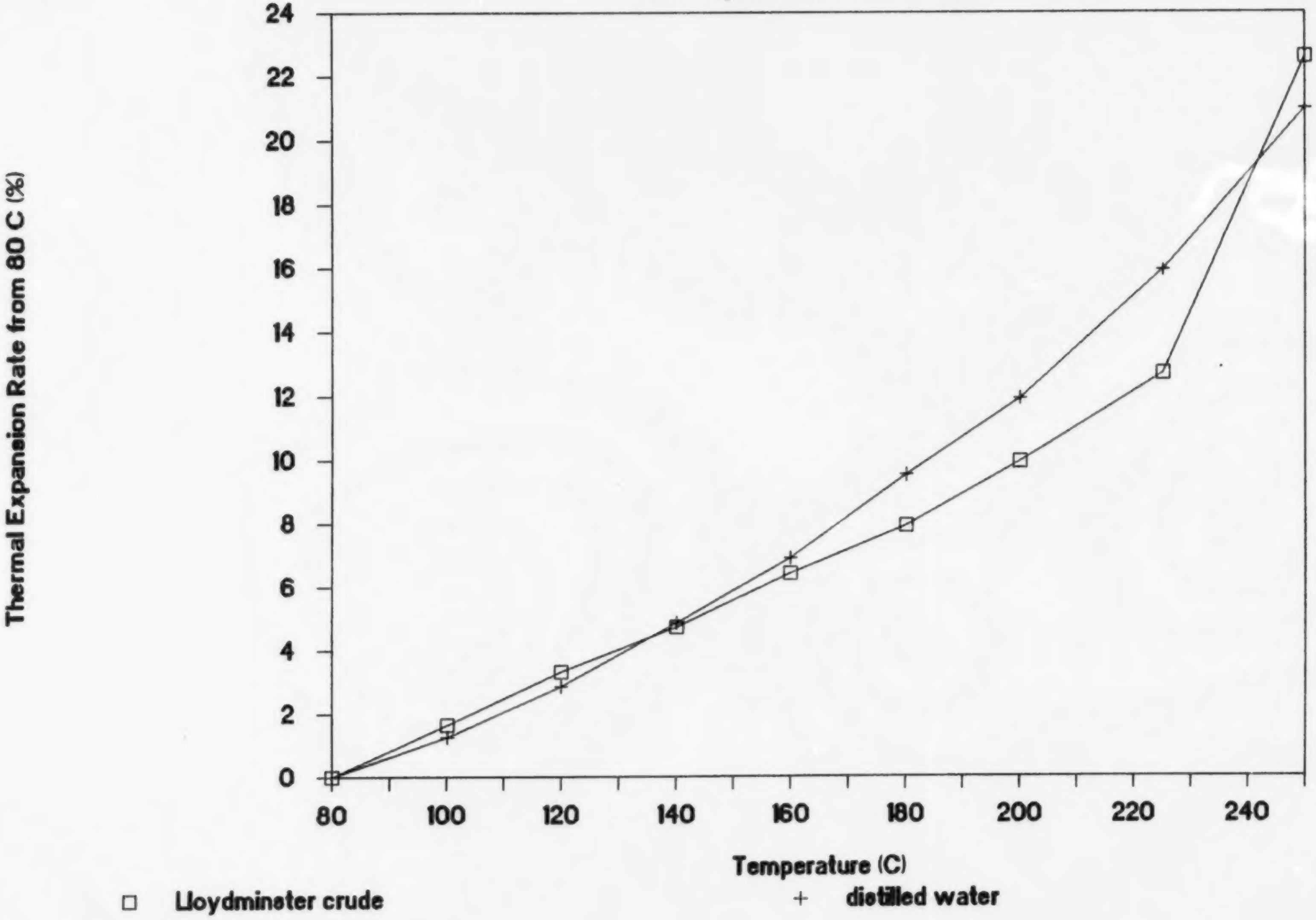


Figure 4.8

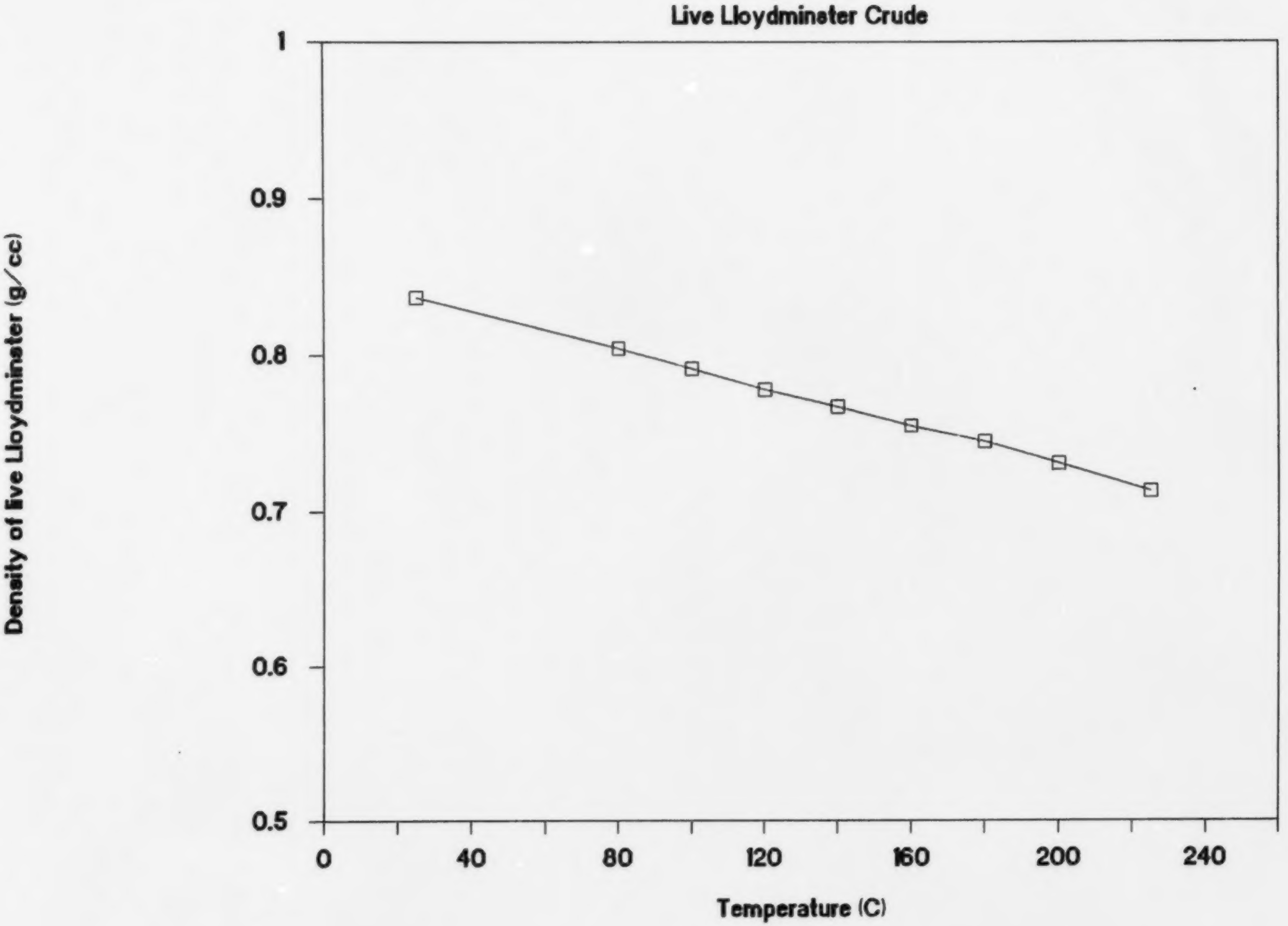
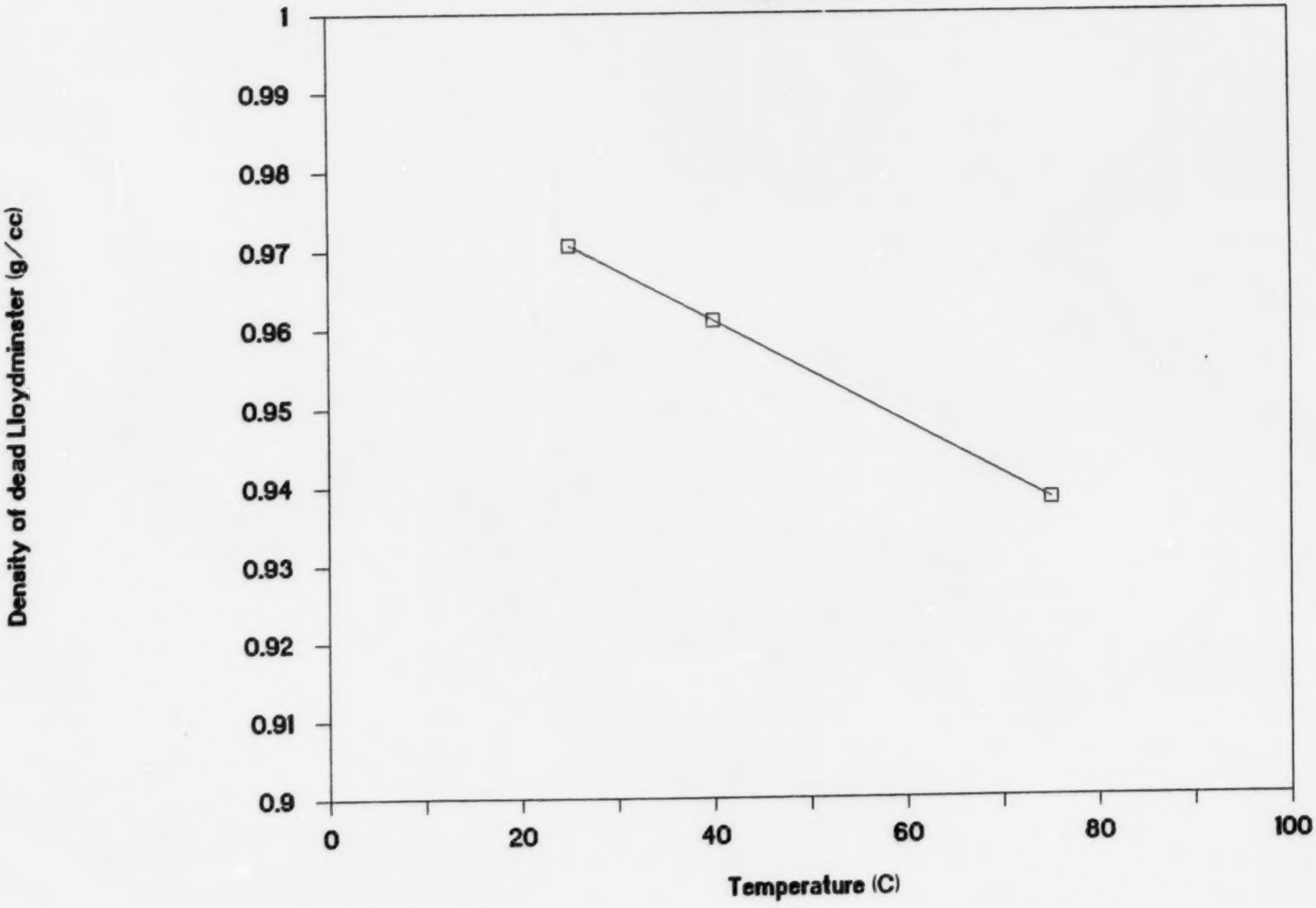

Live Lloydminster Crude
Density of live Lloydminster (g/cc)
1
0.9
0.8
0.7
0.6
0.5
0
40
80
120
160
200
240
Temperature (C)

Figure 4.9

Dead Lloydminster Crude



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3. Jacob, F.A., J.K. Donnelly, J.F. Stanislav and W.Y. Svrcek, "Viscosity of gas saturated bitumen", JCPT, Vol. 19, No. 5, 1982, pp 47-50.

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5. Mehrotra, A.K. and W.Y. Syrcek, "Correlations for properties of bitumen saturated with carbon dioxide, methane and nitrogen, and experiments with combustion gas mixtures", JCPT, Vol. 21, No. 6, 1982, pp 95-104.

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APPENDIX

PV CURVES FOR OIL RECOMBINATION
PHASE 2 -IRREDUCIBLE WATER SATURATION DATA
THERMAL EXPANSION TESTS DATA

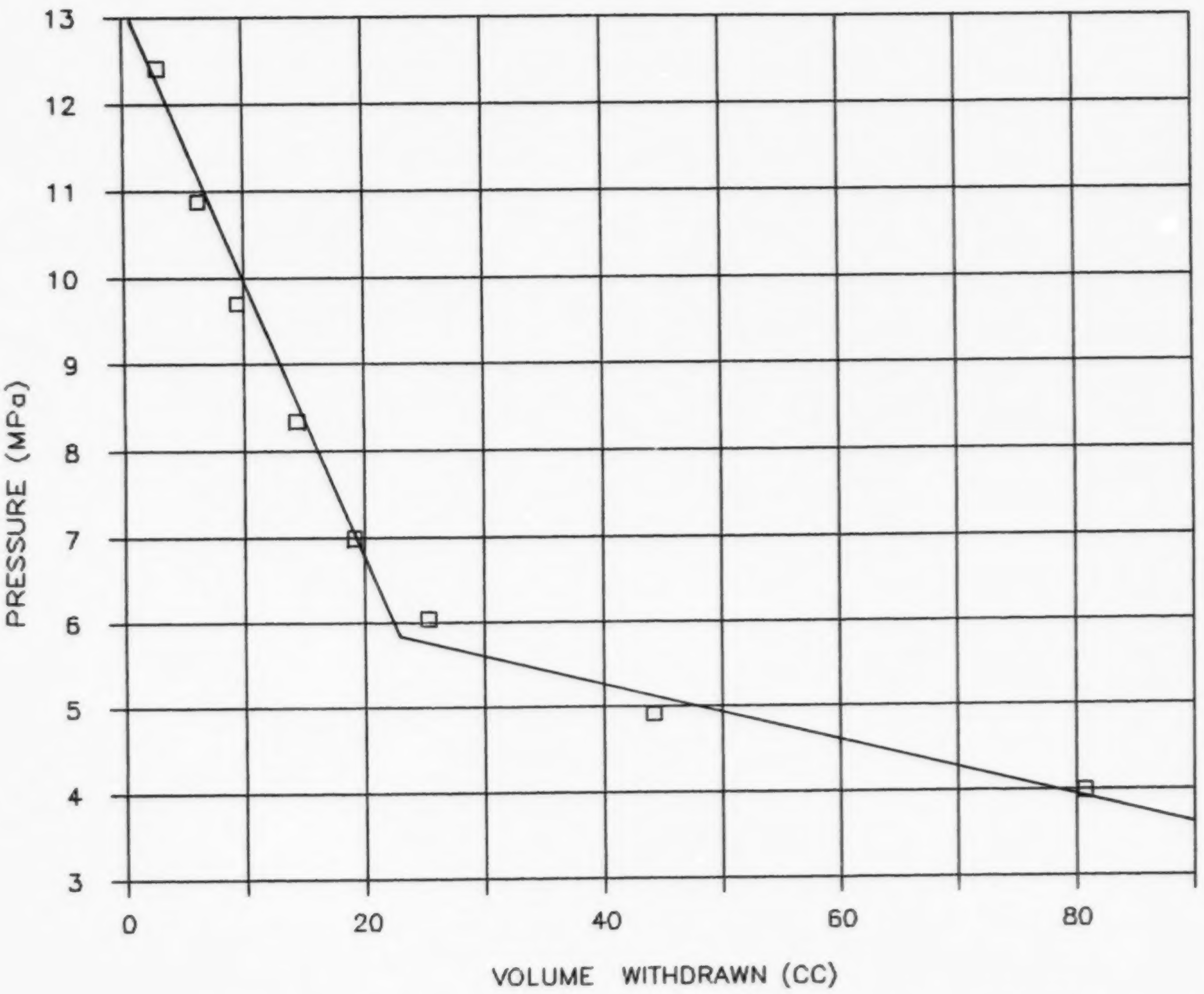

Figure A1 – PV Curve for Nitrogen/Athabasca Recombination

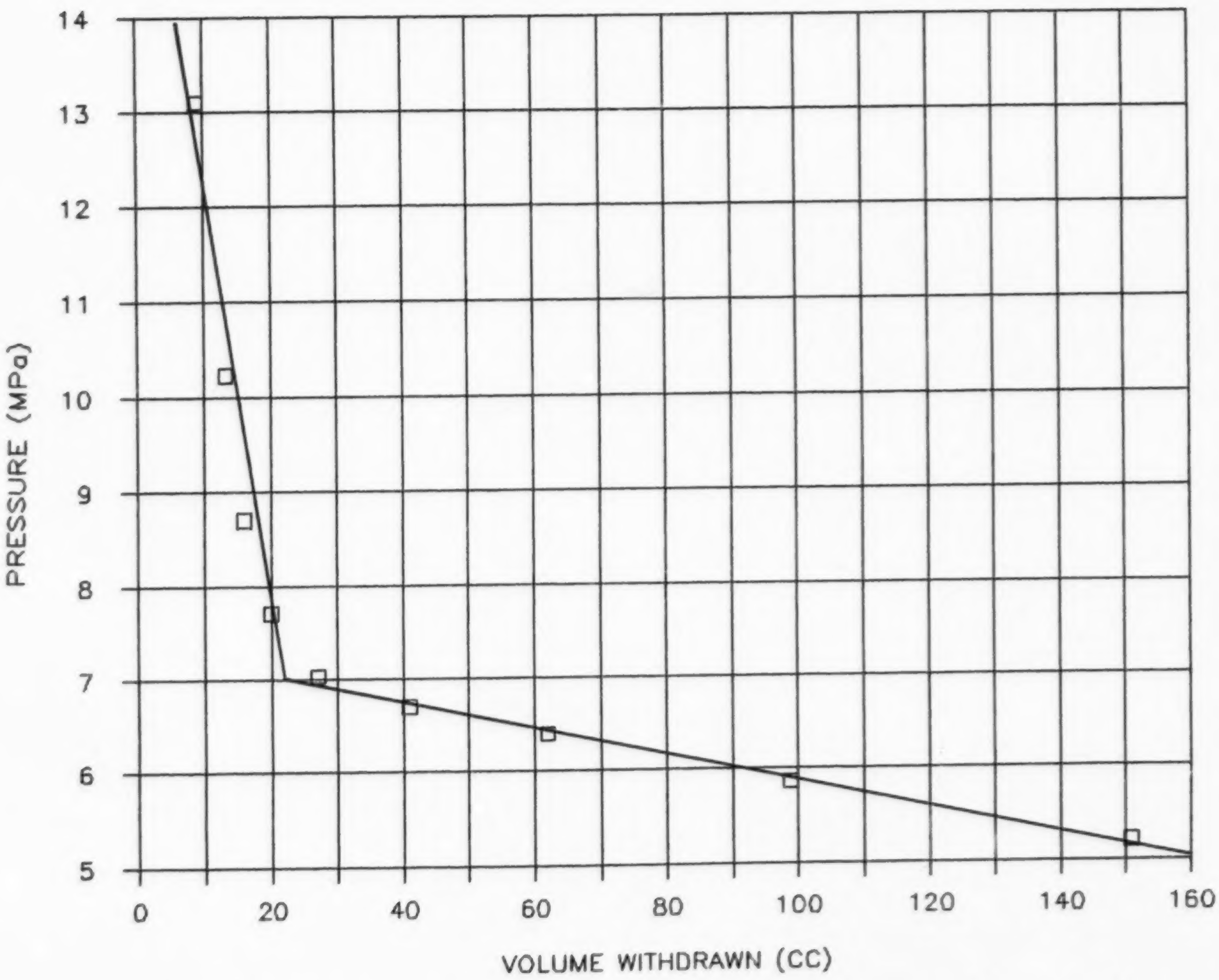

Figure A2 - PV Curve for Carbon Dioxide/Athabasca Recombination

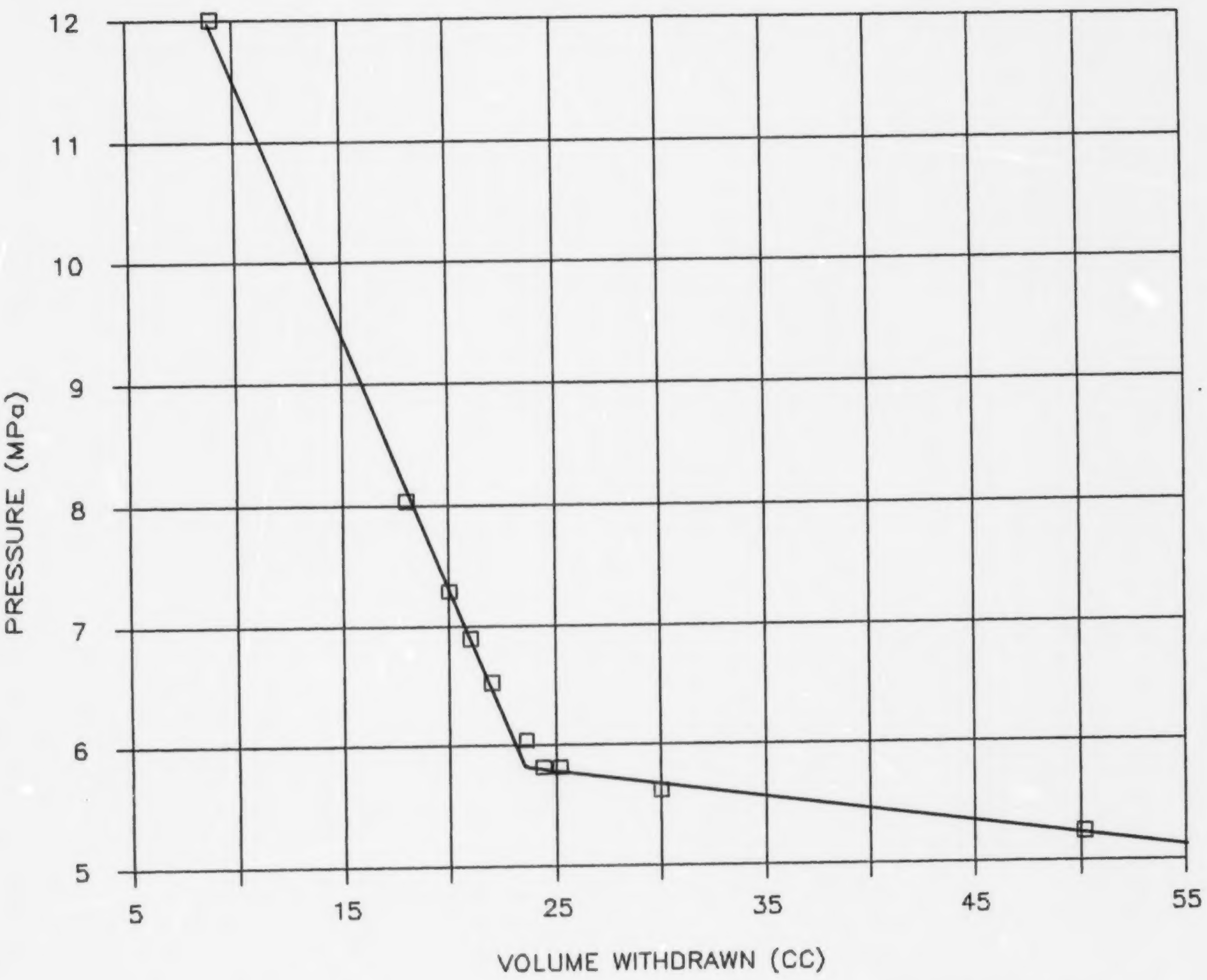

Figure A3 - PV Curve for Methane/Athabasca Recombination

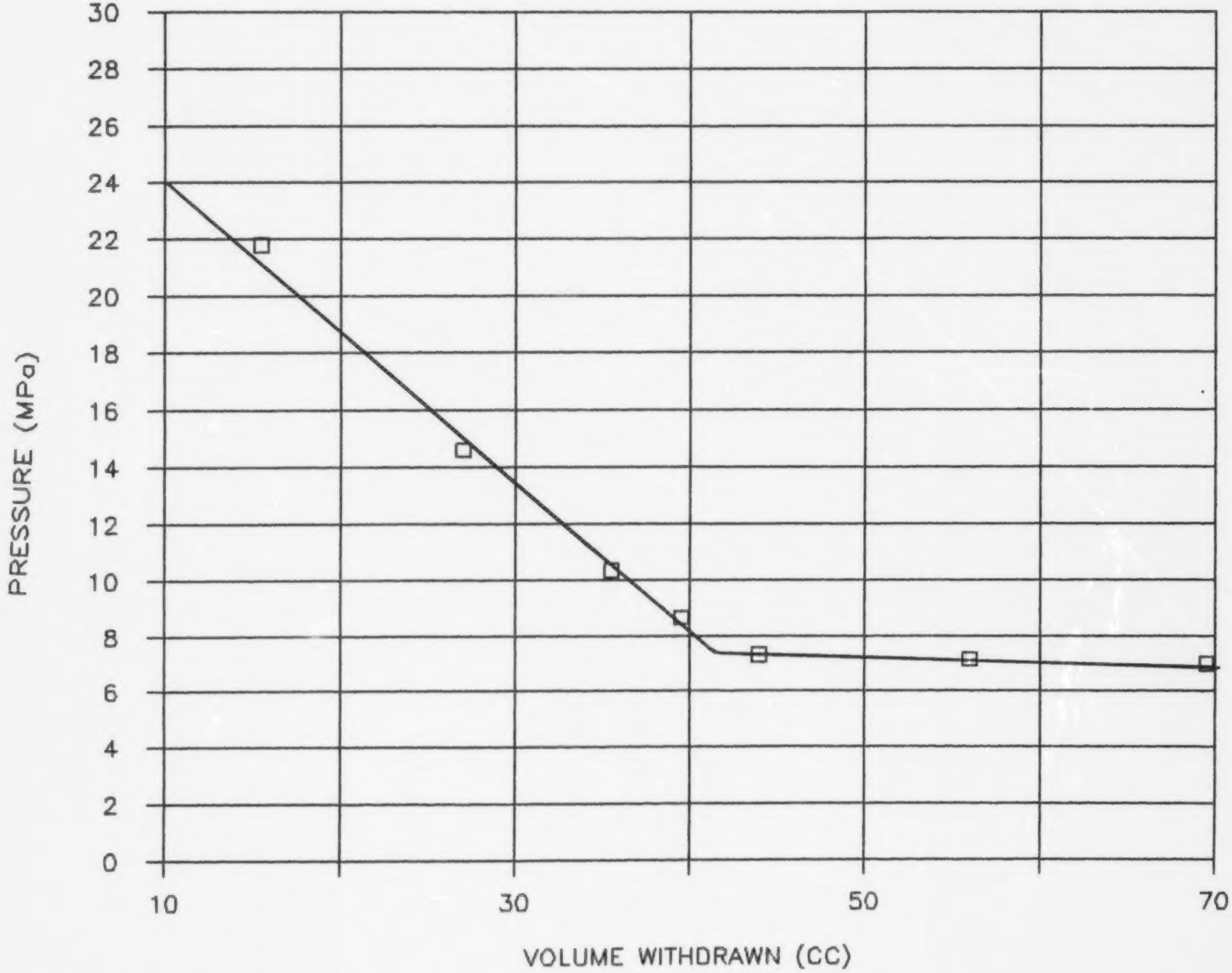

Figure A4 - PV Curve for "Live" Lloydminster Recombination
Batch #1

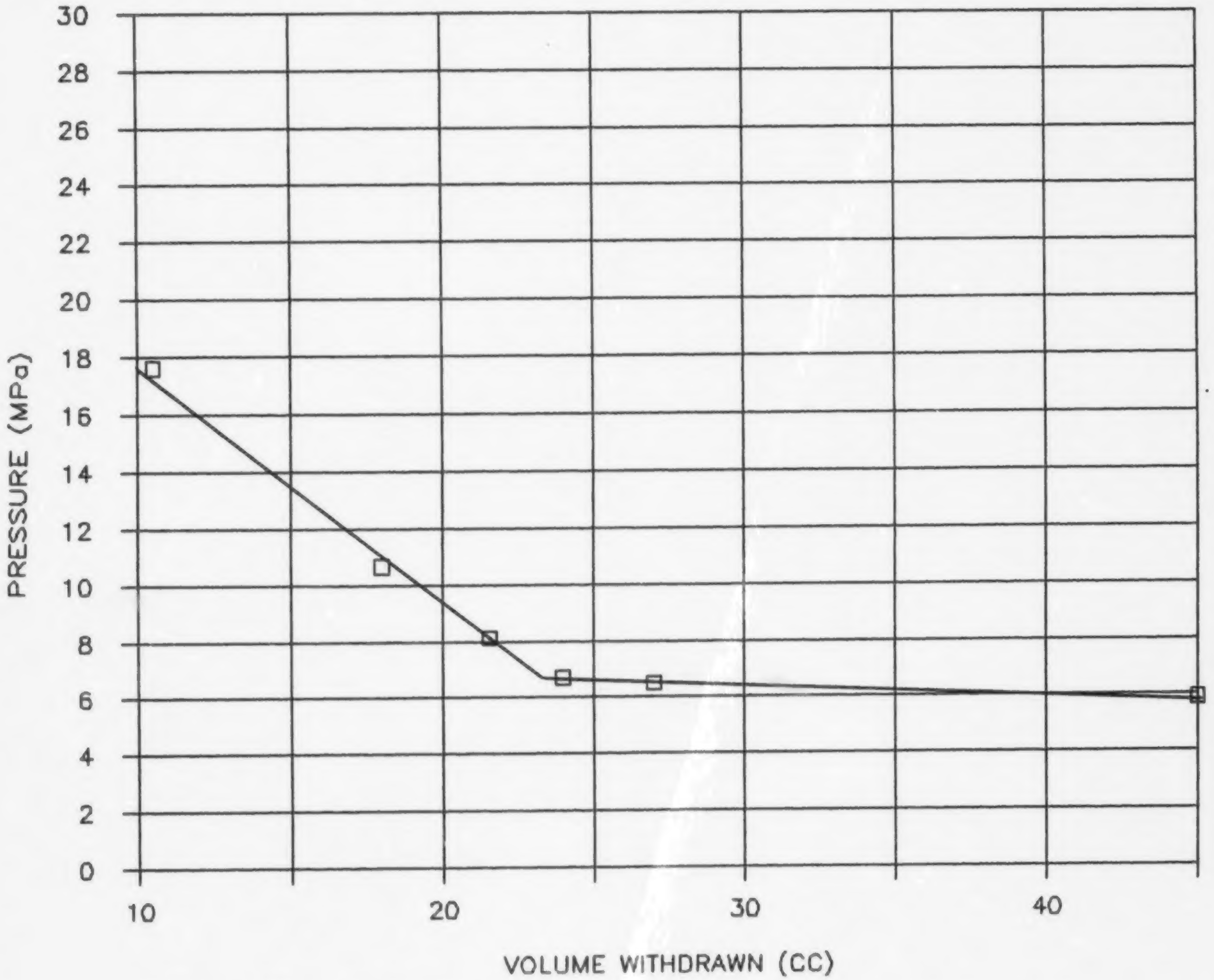

Figure A5 - PV Curve for "Live" Lloydminster Recombination
Batch #2

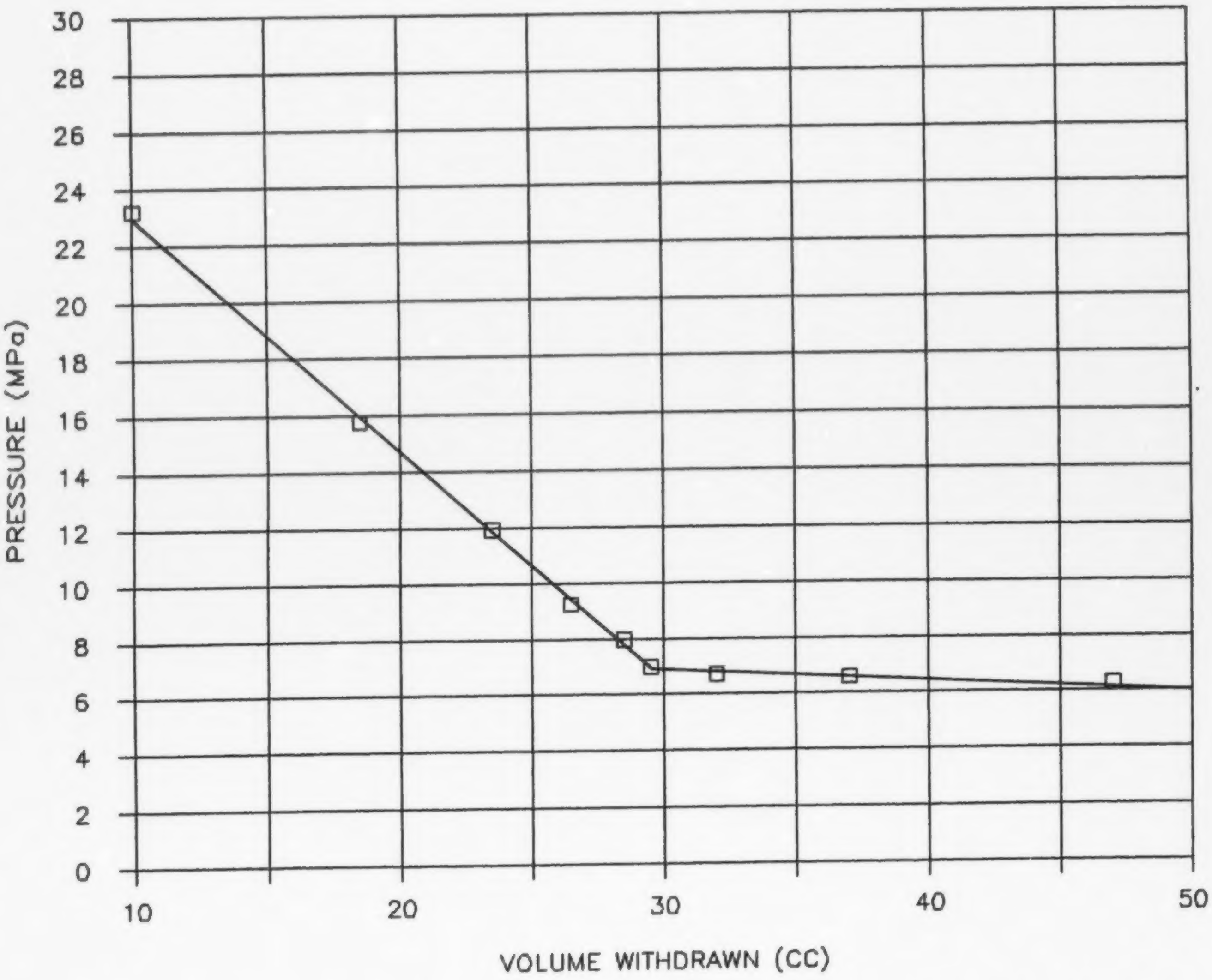

Figure A6 - PV Curve for "Live" Lloydminster Recombination Batch #3

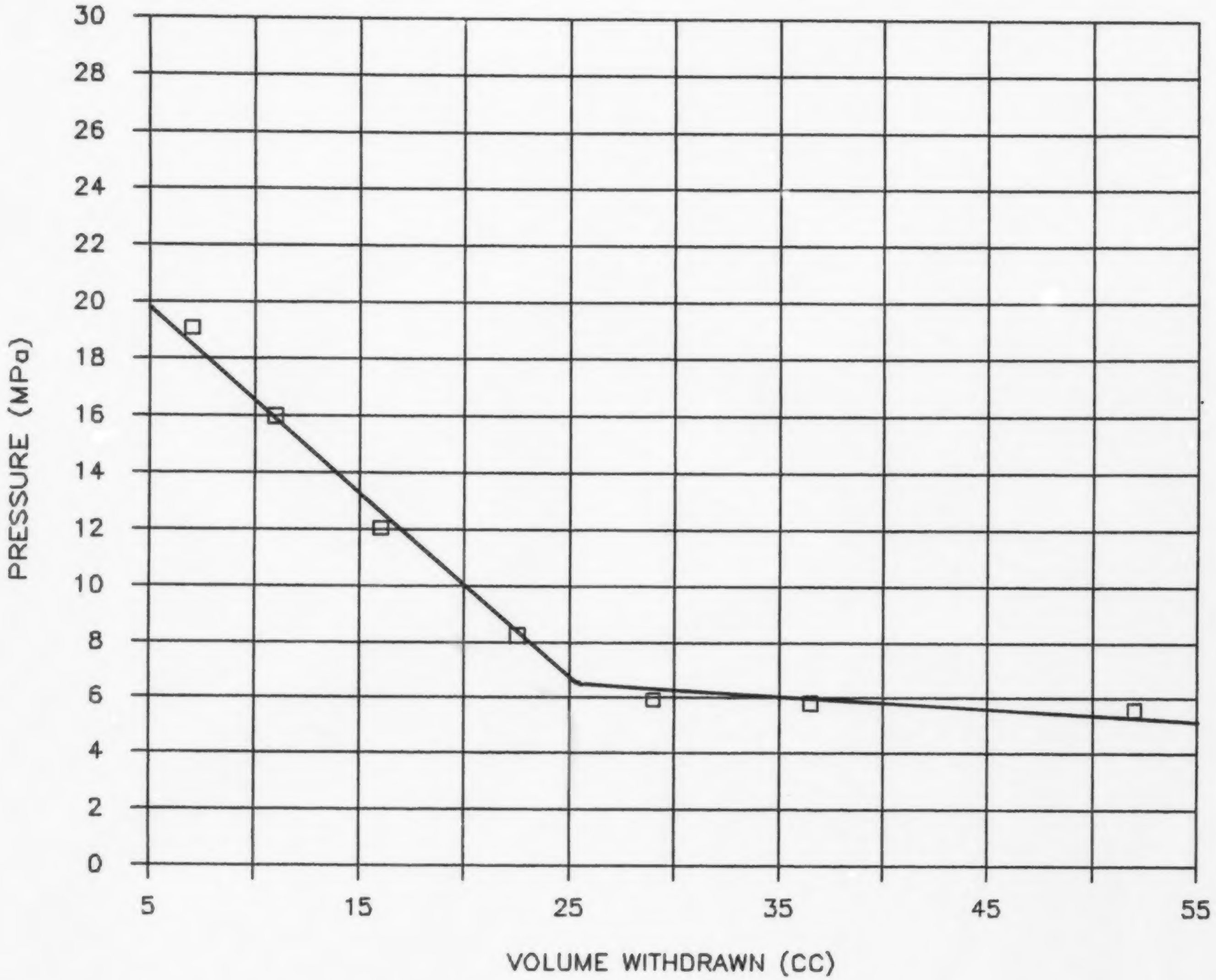

Figure A7 - PV Curve for "Live" Lloydminster Recombination Batch #4

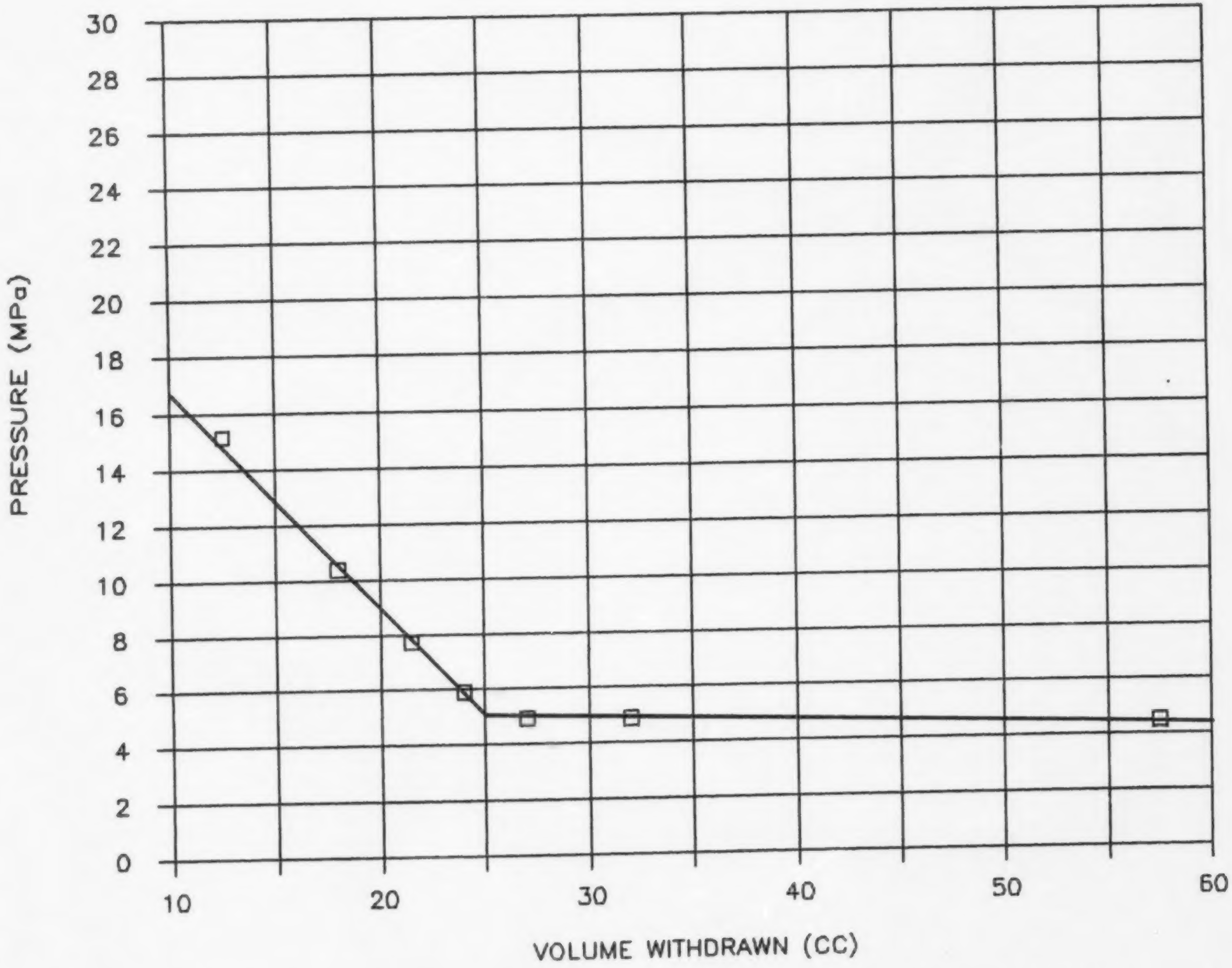

Figure A8 – PV Curve for "Live" Lloydminster Recombination
Batch #5

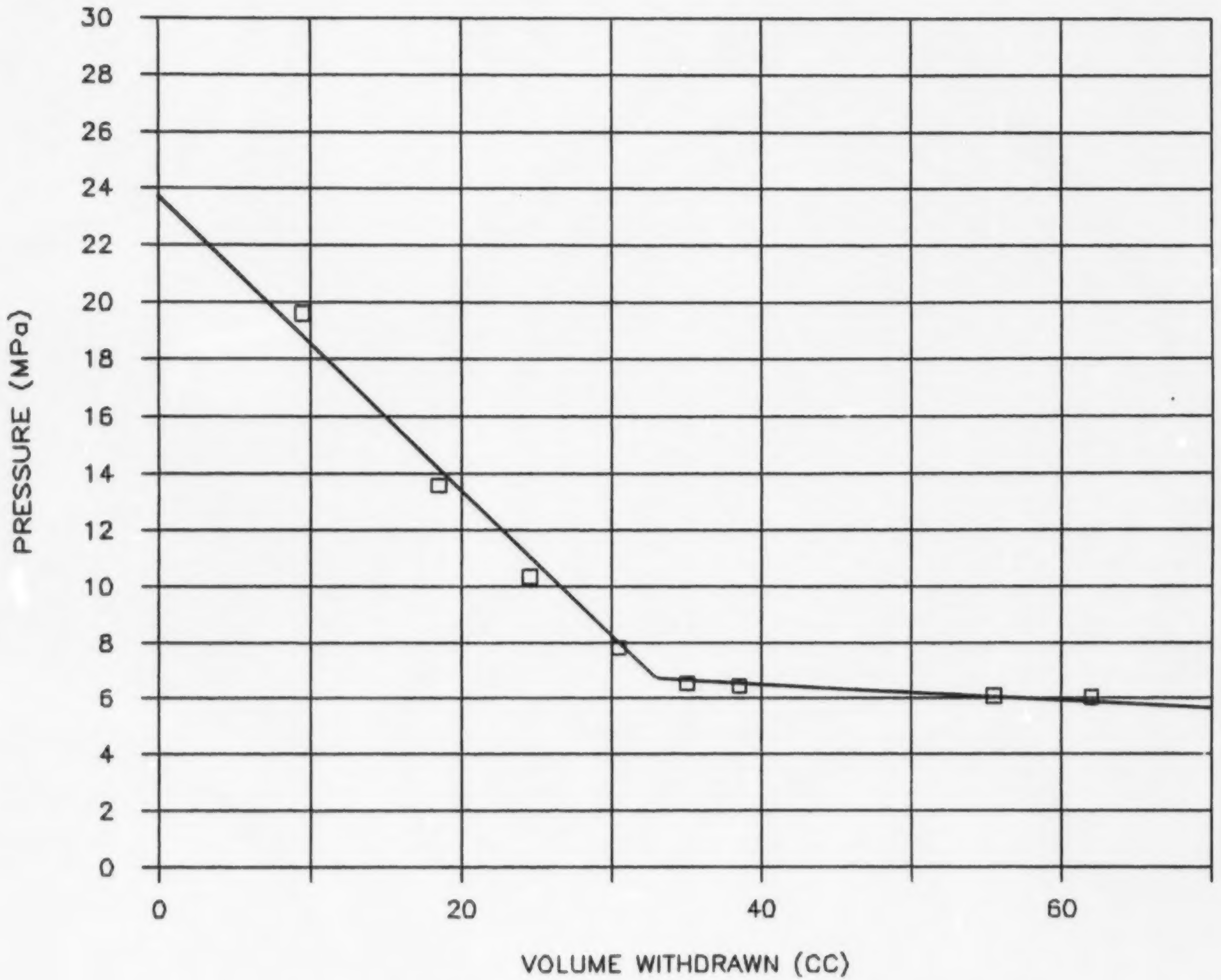

Figure A9 – PV Curve for "Live" Lloydminster Recombination Batch #6

Table A1 - Phase 2
Process: Oilflooding to Irreducible Water Saturation - Original Data

SAMPLE #	PORE VOLUME	POROSITY	kgas	MASS WTR IN SAMP SAT 100%	VLM WTR PRODUCED BY OILFLD @ t	DENSITY OF WTR @ t	MASS WTR IN SAMP AFTER OILFLOOD	Swi
	(cc)	(%)	(mD)	(g)	(cc)	(g/cc)	(g)	(%)
1	60.07	23.8	3724.44	60.07	46.26	1.014	13.16	21.91
2	56.89	23.2	3760.91	56.89	31.96	1.021	24.26	42.64
3	43.06	17.6	96.28	43.06	38.07	1.011	4.57	10.62
4	44.13	17.4	94.34	44.13	36.19	1.020	7.22	16.35
5	54.45	21.9	3369.17	53.91	47.00	1.000	6.91	12.82
6	53.83	21.6	1854.43	53.83	40.37	1.014	12.89	23.95
7	41.90	17.2	127.27	41.90	31.49	1.017	9.87	23.57
8	43.12	18.0	133.00	43.12	36.01	1.020	6.39	14.82
9	50.97	21.1	1014.44	50.97	32.89	1.019	17.46	34.25
10	50.08	20.9	1016.61	50.08	30.83	1.017	18.73	37.39
11	45.57	19.0	116.93	45.57	35.70	1.020	9.16	20.09
12	44.13	18.3	116.67	44.13	36.40	1.020	7.00	15.87
13	51.45	21.3	1097.01	51.45	30.26	1.022	20.52	39.89
14	56.19	22.9	1059.11	56.19	47.30	1.017	8.09	14.39
15	45.70	18.8	116.66	45.70	35.72	1.020	9.27	20.27
16	43.81	18.0	116.17	43.81	30.06	1.020	13.15	30.01
17	55.02	22.7	2765.87	55.02	47.00	1.020	7.08	12.87
18	52.83	22.7	2689.28	52.83	41.34	1.020	10.66	20.18
19	44.78	18.4	120.23	44.78	35.00	1.017	9.19	20.51
20	44.85	18.4	125.09	44.85	29.82	1.017	14.52	32.38
21	53.30	22.7	3074.71	53.30	46.34	1.020	6.03	11.32
22	48.75	21.1	2983.91	48.75	38.05	1.020	9.94	20.39
23	45.55	18.7	131.05	45.55	36.52	1.008	8.74	19.18
24	42.47	17.8	133.02	42.47	34.52	1.020	7.26	17.09
25	52.82	21.8	1227.81	51.34	40.13	1.000	11.21	21.83
26	54.63	22.3	635.92	53.26	41.89	1.000	11.37	21.35
27	50.12	21.0	3598.00	48.87	37.80	1.000	11.07	22.65
28	42.57	17.7	100.72	41.38	34.76	1.000	6.62	16.00
29	42.61	18.0	96.42	41.54	33.17	1.000	8.37	20.15
30	47.85	20.1	616.60	46.65	40.30	1.000	6.35	13.61
31	54.14	22.2	719.30	52.79	41.78	1.000	11.01	20.86
32	42.23	18.2	94.34	41.17	31.60	1.000	9.57	23.25
33	41.97	18.0	95.92	40.92	32.80	1.000	8.12	19.84

Table A2 - Thermal Expansion Data for "Dead" Athabasca

Cylinder 1 volume = 506.5 mL
Cylinder 2 volume = 105.5 mL

Volume of oil in cylinder 1 = 295 mL
Volume of water in cylinder 1 = 211.5 mL

Temperature (C)		Mass Expelled (g)
From	To	
80	116	13.82
116	144	27.05
144	182	43.15
182	215	61.56
215	246	81.43

Table A3 - Thermal Expansion for CO_2 Saturated Athabasca

Cylinder 1 volume = 506.5 mL
Cylinder 2 volume = 507.0 mL

Volume of oil in cylinder 1 = 165.91 mL
Volume of water in cylinder 1 = 340.59 mL

Temperature (C)		Mass Expelled (g)
From	To	
80	96	9.38
96	141	49.44
141	188	99.91
188	211	137.41
211	243	623.86

Table A4 - Thermal Expansion for Methane Saturated Athabasca

Cylinder 1 volume = 506.5 mL
Cylinder 2 volume = 507.0 mL

Volume of oil in cylinder 1 = 151.30 mL
Volume of water in cylinder 1 = 355.20 mL

Temperature (C)		Mass Expelled (g)
From	To	
78	82	3.10
82	98	13.25
98	144	53.00
144	190	107.80
190	216	161.59
216	247	466.15

Table A5 - Thermal Expansion for N_2 Saturated Athabasca

Cylinder 1 volume = 506.5 mL
Cylinder 2 volume = 105.5 mL

Volume of oil in cylinder 1 = 190.85 mL
Volume of water in cylinder 1= 421.15 mL

Temperature (C)		Mass Expelled (g)
From	To	
78	83	1.72
83	99	8.10
99	146	30.25
146	194	57.49

Table A6 - Thermal Expansion for "Live" Lloydminster

Cylinder 1 volume = 515 mL
Cylinder 2 volume = 94 mL

Volume of oil in cylinder 1 = 346.60 mL
Volume of water in cylinder 1 = 168.40 mL

Temperature (C)		Mass Expelled (g)
From	To	
80	100	8.40
100	120	17.40
120	140	26.15
140	160	35.55
160	180	45.11
180	200	55.37
200	225	69.57
225	250	104.19